DIRECT TESTIMONY AND EXHIBITS OF

ANTHONY M. SANDONATO

ON BEHALF OF

THE SOUTH CAROLINA OFFICE OF REGULATORY STAFF

DOCKET NO. 2019-224-E

DOCKET NO 2019-225-E

IN RE: SOUTH CAROLINA ENERGY FREEDOM ACT (HOUSE BILL 3659) PROCEEDING RELATED TO S.C. CODE ANN. SECTION 58-37-40 AND INTEGRATED RESOURCE PLANS FOR DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.

A. My name is Anthony Sandonato. My business address is 1401 Main Street, Suite 900, Columbia, South Carolina, 29201. I am employed by the South Carolina Office of Regulatory Staff ("ORS") in the Energy Operations Division as a Senior Regulatory Manager.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I received my Bachelor of Science in Nuclear Engineering from North Carolina State University in 2011. Prior to my employment with ORS, I was employed as an analyst with a global professional, technology, and marketing service firm working with large investor-owned utilities on energy efficiency program design and implementation. I joined ORS in 2016, and, in October 2019, I was promoted to my current position in the Energy Operations Division.

Q. HAVE YOU TESTIFIED BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA ("COMMISSION")?

A. Yes. I have previously testified before the Commission.

Q. WHAT IS THE MISSION OF ORS?

A. ORS represents the public interest as defined by the South Carolina General Assembly as:

> [T]he concerns of the using and consuming public with respect to public utility services, regardless of the class of customer, and preservation of continued investment in and maintenance of utility facilities so as to provide reliable and high-quality utility services.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to set forth and support ORS's recommendations resulting from the examination and review of Duke Energy Carolinas, LLC's ("DEC") Integrated Resource Plan ("IRP") and Duke Energy Progress, LLC's ("DEP") IRP, (Collectively "Duke Energy" or the "Companies") and associated filings in the dockets to determine compliance with certain sections of the South Carolina Energy Freedom Act ("Act 62" or the "Act"). ORS retained the consulting services of J. Kennedy and Associates, Inc. ("Kennedy and Associates") to assist in the review and analysis of the Companies' IRP.

Q. WAS THE EXAMINATION AND REVIEW OF DUKE ENERGY'S FILINGS PERFORMED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes. The review was performed by me or under my supervision.

Q. PLEASE EXPLAIN EXHIBIT AMS-1 AND AMS-2.

A. Exhibit AMS-1 is the Review of Duke Energy Carolinas, LLC 2020 Integrated Resource Plan Report (the "DEC Report"). Exhibit AMS-2 is the Review of Duke Energy

Progress, LLC 2020 Integrated Resource Plan Report (the "DEP Report") (Collectively the "ORS Reports"). The ORS Reports were developed for ORS by Kennedy and Associates and provide a detailed analysis of both the DEC and DEP IRPs. The direct testimonies of ORS witnesses Philip Hayet, Lane Kollen and Stephen J. Baron discuss their respective reviews, analyses, and recommendations.

Q. PLEASE DETAIL THE CRITERIA BY WHICH YOU EVALUATED THE COMPANIES' IRPS.

A. ORS relied on the requirements provided in S.C. Code Ann. §58-37-40(B)(1) (Rev. 2019)**,** which requires an IRP for an electrical utility to include the following:

> (a) a long-term forecast of the utility's sales and peak demand under various reasonable scenarios;
> (b) the type of generation technology proposed for a generation facility contained in the plan and the proposed capacity of the generation facility, including fuel cost sensitivities under various reasonable scenarios;
> (c) projected energy purchased or produced by the utility from a renewable energy resource;
> (d) a summary of the electrical transmission investments planned by the utility;
> (e) several resource portfolios developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's service obligations. Such portfolios and evaluations must include an evaluation of low, medium, and high cases for the adoption of renewable energy and cogeneration, energy efficiency, and demand response measures, including consideration of the following:
> (i) customer energy efficiency and demand response programs;
> (ii) facility retirement assumptions; and
> (iii) sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks;
> (f) data regarding the utility's current generation portfolio, including the age, licensing status, and remaining estimated life of operation for each facility in the portfolio;
> (g) plans for meeting current and future capacity needs with the cost estimates for all proposed resource portfolios in the plan;
> (h) an analysis of the cost and reliability impacts of all reasonable options available to meet projected energy and capacity needs; and,

> (i) a forecast of the utility's peak demand, details regarding the amount of peak demand reduction the utility expects to achieve, and the actions the utility proposes to take in order to achieve that peak demand reduction.

Q. DO THE COMPANIES' IRPS COMPLY WITH S.C. CODE ANN. § 58-37-40(B)(1)?

A. Yes. The Companies' IRPs as filed with the Commission include the elements required under the Act. Each element of Act 62 and a corresponding analysis of the Companies' IRPs compliance is discussed in detail in the ORS Reports contained in Exhibits AMS-1 and AMS-2.

Q. PLEASE DISCUSS S.C. CODE ANN. §58-37-40(C).

A. Section 58-37-40(C), as revised by Act 62, identifies the following factors that an IRP should appropriately balance to determine if the Companies' plan is the most reasonable:

> (a) resource adequacy and capacity to serve anticipated peak electrical load, and applicable planning reserve margins;
> (b) consumer affordability and least cost;
> (c) compliance with applicable state and federal environmental regulations;
> (d) power supply reliability;
> (e) commodity price risks;
> (f) diversity of generation supply; and
> (g) other foreseeable conditions that the commission determines to be for the public

Q. PLEASE SUMMARIZE ORS'S RECOMMENDATION RELATED TO THE COMPANIES' IRPS.

A. ORS recommends the Companies modify their 2020 IRPs. Each ORS recommendation listed below is discussed in more detail in the ORS Reports and testimonies of ORS witnesses Baron, Kollen and Hayet. The specific modifications recommended by ORS including the corresponding item number as found in the Executive Summaries of the ORS Reports are listed in the table below.

Item	Recommendations for DEC and DEP in this IRP
4	ORS recommends the Companies provide a detailed discussion in the IRP Report or appendices that explains how the results of the Astrapé 2018 Solar Capacity Value Study were used to derive the assumed winter peak standalone solar capacity value of 1%. We recommend this information be included in a modified IRP in this proceeding.
5	ORS recommends the Companies provide additional justification for selecting the Base Energy Efficiency ("EE")/Demand Side Management ("DSM") case as opposed to the High EE/DSM case for use in Portfolio A, given that the High EE/DSM case may provide greater customer benefits. We recommend this information be included in a modified IRP in this proceeding.
6	ORS recommends that in addition to the sensitivity cases included in Table A-9, the Companies also evaluate high and low levels of EE/DSM using high fuel/CO_2 and low fuel/CO_2 assumptions. We recommend this information be included in a modified IRP in this proceeding.
9	ORS recommends the Companies provide tables summarizing the capital and operations and maintenance ("O&M") costs for compliance with environmental regulations by unit and by environmental regulation, and include descriptions explaining those costs. We recommend this information be included in a modified IRP in this proceeding.
10	To ensure there are no inconsistencies in modeling data, we recommend the Companies create a cross reference table that compares each resource modeled in PROSYM, including generating units, demand response, purchase contracts, sales contracts, EE, etc. to the corresponding data in the Load, Capacity and Reserves ("LCR") table, on a resource by resource basis. We recommend this be developed for both the Base Case with CO_2 and Base Case without CO_2 cases, and cover all of the years in the study period. We recommend this information be provided in a modified IRP in this proceeding.
11	Recognizing that the Companies plan to pursue relicensing of the Oconee nuclear units' operating licenses in 2021, we recommend the Companies supply additional information regarding its relicensing plans (including a timeline) and its plans to conduct economic evaluations to assess the benefits of relicensing the units. We recommend the Companies provide additional insight into why it is beginning this process so far in advance of the relicensing dates. We recommend this information be provided in a modified IRP in this proceeding.

Item	Recommendations for DEC and DEP in this IRP
12	DEC Only - The Bad Creek Pumped Hydro units' licenses are set to expire in 2027. However, the IRP does not provide details on the relicensing status of these units. Since these units will need to go through a relicensing process with the Federal Energy Regulatory Commission ("FERC") soon, we recommend that DEC provide the status of its plans to relicense the units, including any actions it will have to take as part of the relicensing process and any costs that it will incur to relicense the units. We recommend this information be provided in a modified IRP in this proceeding.
13	DEC Only - ORS recommends DEC provide additional clarification regarding its plans for the retirement of the Allen units, including details about any transmission impacts, an explanation of the steps being pursued to receive final approval within DEC and from any regulatory body, and a timeline for conducting these activities. We recommend this information be provided in a modified IRP in this proceeding.
14	ORS recommends the Companies provide evidence that the optimal retirement dates that were determined with the Sequential Peaker Method ("SPM") are comparable to the optimal retirement dates the System Optimizer model would produce if it were used in the retirement study. We recommend this information be provided in a modified IRP in this proceeding.
15	ORS recommends the Companies supply additional information explaining the basis for how Combined Heat and Power ("CHP") resources were added to the short-term action plan, and explain why CHP resources were not treated as selectable resources in the economic optimization process, if in fact they were not. We recommend this information be provided in a modified IRP in this proceeding.
16	ORS recommends the Companies provide additional justification for its Combustion Turbine ("CT") capital cost assumption. We recommend this information be provided in a modified IRP in this proceeding.
17	ORS recommends the Companies provide additional justification for its Battery Energy Storage fixed O&M cost and capacity factor assumptions. We recommend this information be provided in a modified IRP in this proceeding.
18	ORS recommends the Companies include an additional solar generic resource option in its IRP modeling assumptions that reflects the kind of solar Purchase Power Agreements ("PPA") prices that may be available in the market. As a proxy, the Companies could assume $38/ megawatt-hour ("MWh") as the solar PPA cost. We recommend this be addressed in a modified IRP in this proceeding.

Item	Recommendations for DEC and DEP in this IRP
20	ORS recommends the Companies provide a table identifying each renewable resource option that was modeled, and include whether the resource was forced-in or economically selected (System Optimizer or other approach), the reason the resource was forced-in (e.g. Competitive Procurement of Renewable Energy Program (“CPRE”), Act 236, etc.), whether the resource is a designated, mandated, or undesignated resource, and where the resource is found in the PROSYM database and in the LCR tables for reconciliation purposes. We recommend this information be provided in a modified IRP in this proceeding.
21	ORS recommends the Companies include post in-service capital costs for new resource additions in its capital cost model and its Present Value of Revenue Requirement (“PVRR”) calculations for each Portfolio and each sensitivity of each Portfolio. We recommend this be addressed in a modified IRP in this proceeding.
22	The average retail rate impacts are an important consideration when assessing whether Portfolios and the pathways reflected in those Portfolios are reasonable. This should be considered in this IRP and future IRPs, but it does not require a modified IRP in this proceeding.
23	ORS recommends the Companies revise the calculation of the average retail rate impact on customers so that the assumptions and methodologies are consistent with the calculations of the PVRR, except for the levelization of the capital-related costs. We recommend this be included in a modified IRP in this proceeding.
24	ORS recommends the Companies provide additional details and status updates about resources included in the action plan, including coal retirements, the Lincoln CT project, unnamed energy storage projects, nuclear uprates, Bad Creek upgrades, and unnamed CHP projects. We recommend this information be included in a modified IRP in this proceeding.

Q. DO THE COMPANIES’ IRPS INCLUDE RESOURCES SELECTED ONLY TO MEET CERTAIN STATE STATUTORY REQUIREMENTS AND DUKE ENERGY’S CORPORATE CARBON REDUCTION TARGETS?

A. Yes. The Companies include new base solar resources that are not selected on an economic basis. ORS will review the costs of these new resources and new programs as part of the Companies next rate proceedings.

Q. DOES THE ORS REVIEW ADDRESS THE NOTIFICATION FILED ON FEBRUARY 2, 2021 BY DEC INFORMING THE COMMISSION OF THE REVISED RETIREMENT DATE FOR ALLEN UNIT 3?

A. No. DEC filed a letter with the Commission on February 2, 2021, accelerating the retirement date of the coal unit, Allen Unit 3, from December 31, 2021 to March 31, 2021. However, the 2020 IRP reflects the retirement date of Allen Unit 3 as December 31, 2021. Given the timing of DEC's filing, ORS performed its review and analysis based upon the 2020 IRP retirement assumptions. After an initial review of the February 2, 2021 notification of the revised retirement date for Allen Unit 3, it is ORS's opinion that the earlier retirement of this coal unit will not impact ORS's recommendations. However, ORS reserves its rights to update its analysis and testimony should it be necessary.

Q. WILL YOU UPDATE YOUR DIRECT TESTIMONY BASED ON INFORMATION THAT BECOMES AVAILABLE?

A. Yes. ORS fully reserves the right to revise its recommendations via supplemental testimony should new information not previously provided by the Company, or other sources, becomes available.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Review of Duke Energy Carolinas, LLC 2020 Integrated Resource Plan Docket No. 2019-224-E

South Carolina
Office of Regulatory Staff

February 5, 2021

Review of Duke Energy Carolinas, LLC
2020 Integrated Resource Plan

Pursuant to Section 58-37-40, South Carolina Code of Laws

February 5, 2021

Prepared for the South Carolina Office of Regulatory Staff
by
J. Kennedy and Associates, Inc.

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Executive Summary

The South Carolina Office of Regulatory Staff ("ORS") provides this review of Duke Energy Carolinas, LLC's ("DEC" or "Company") 2020 Integrated Resource Plan ("IRP") filed September 1, 2020, in Docket No. 2019-224-E. In this report ("ORS Report"), when discussed collectively, DEC and its affiliated utility, Duke Energy Progress, LLC ("DEP"), will be referred to as "Duke Energy."

ORS, with the assistance of J. Kennedy and Associates, Inc. ("JKA"), evaluated DEC's IRP to determine if DEC complied with the statutory requirements of S.C. Code Ann. §58-37-40 ("Section 40"), as amended by the South Carolina Energy Freedom Act ("Act 62"), and the requirements of the Public Service Commission of South Carolina's ("Commission") Order No. 98-502.

Act 62 was signed into law by Governor McMaster on May 16, 2019. Act 62 amended and expanded the prior Section 40 IRP requirements. Act 62 includes a list of specific information that each utility must provide in its IRP, requires that the Commission determine whether the utility's IRP represents the "most reasonable and prudent means of meeting the electrical utility's energy and capacity needs as of the time the plan is reviewed,"[1] and sets forth seven factors for the Commission to consider in its determination of whether to approve, require modifications, or reject the utility's resource plan, among other procedural and substantive requirements.

Act 62 also states that any resource plan accepted by the Commission "shall not be determinative of the reasonableness or prudence of the acquisition or construction of any resource or the making of any expenditure."[2] Act 62 further states that the utility retains the burden to prove in a future cost recovery proceeding that any investment and expenditure it makes is reasonable and prudent.[3]

DEC is an electric utility that provides electric retail service to 2.7 million customers located in a 24,000-square-mile service area in western South Carolina and central and western North Carolina.[4] DEC had 2019 summer and winter peak loads of 17,736 and 16,880 megawatts ("MW")[5] respectively, and an installed capacity base of about 23,200 MW of DEC-owned resources.[6]

DEC's IRP is the same for South Carolina and North Carolina due to the fact that it operates as a single system without consideration of the geographic boundaries of the

[1] S.C. Code Ann. § 58-37-40(C)(2).
[2] S.C. Code Ann. § 58-37-40(C)(4).
[3] *Id.*
[4] DEC 2020 IRP Report, filed September 1, 2020, pgs. 4 and 26.
[5] *Id.* pgs. 236 and 237.
[6] *Id.* pg. 4.

two states. DEC did not develop a separate IRP for each state. Although DEC's IRP was developed on a standalone basis (not consolidated with DEP), it addresses the fact that DEC and DEP operate under a combined dispatch, which provides certain reliability and cost benefits for planning purposes. The Company states, "[i]t is important to note that DEC and DEP cannot develop different IRPs for each system [in each state]. Accordingly, it is in all parties' interest that the resulting IRPs accepted or approved in each state are consistent with one another."[7] Nevertheless, there are different statutory and regulatory requirements in each state that affect the Company's IRP, including the selection and magnitude of demand side management ("DSM") and energy efficiency ("EE") programs, selection of new generation resources, portfolios considered, and costs of each portfolio, among other issues. For example, a significant portion of the new renewable resources in the IRP are "forced in" (not economically added) to comply with North Carolina, not South Carolina, statutory and other regulatory requirements.

While the Company's IRP was developed without differentiation by state, when making cost allocations, the Commission has the authority to differentiate and directly assign or allocate the costs of certain resources for ratemaking purposes.. Such direct assignments or allocations typically are addressed in ratemaking proceedings, not IRP proceedings, although the issues can be identified in the IRP proceedings.

This is the first DEC IRP to address the Act 62 requirements concerning a comprehensive IRP. Act 62 requires that a utility file a comprehensive IRP every three years and an updated IRP in the intervening two years.[8] The Company states that the objectives of an IRP are to "balance the need for system reliability, consumer affordability and increasingly clean energy supply,"[9] and it also states a utility does this by providing stakeholders, "projections or forecasts of how the utility's supply-side and demand-side resources could change over a 15-year planning horizon."[10]

The DEC IRP provides a series of six resource Portfolios, which it refers to as "potential pathways for how the Company's resource portfolio may evolve over the 15-year period (2021 through 2035) based on current data and assumptions across a variety of scenarios."[11] The first plan that the Company developed, "Portfolio A," reflects current federal and state environmental policies (also referred to as the "Base Case without CO_2" plan). Portfolio B is similar to Portfolio A, but it assumes that a form of federal carbon policy will be implemented (also referred to as the "Base Case with CO_2" plan). The

[7] Direct Testimony of Glen Snider, pg. 9, ln.16.
[8] Duke Energy notes that its historical practice has been to file a comprehensive IRP every two, and it appears that Duke Energy would prefer to maintain that schedule to be consistent with North Carolina IRP requirements.
[9] Direct Testimony of Glen Snider, pg. 8, ln. 4.
[10] *Id*. pg. 7, ln. 22.
[11] DEC 2020 IRP, pg. 5.

Company developed four additional Portfolios that would achieve greater levels of CO_2 reductions compared to Portfolio B based on earlier retirements of existing coal resources and different selections and additions of new renewable, gas-fired, storage, and advanced nuclear resources.

The Company's parent company, Duke Energy, Inc., has established a corporate-wide CO_2 reduction goal that is more stringent than present statutory and regulatory requirements at the federal and state levels. The parent company's corporate CO_2 reduction goal is an important theme discussed throughout its IRP Report and is the driving factor in the retirement of existing resources and selection and addition of new resources in four of the six Portfolios, Portfolios C through F. Duke Energy, Inc.'s corporate-wide goal is to reduce CO_2 emissions at least 50% from 2005 levels by 2030 and to achieve net-zero CO_2 emissions by 2050.[12] The Company states that all six of the Portfolios could achieve the Duke Energy, Inc. corporate-wide goal CO_2 reduction goal through the phased retirement of all its existing coal-fired generating units and new renewable resource additions. However, the Company acknowledges that it will have to protect customer rates and ensure the reliability of its utility systems. In the IRP, DEC evaluated two different coal retirement schedules. One schedule reflects coal retirements based on an economic retirement study performed as part of the IRP. That coal retirement schedule is reflected in Portfolios A, B, and F. The other schedule accelerates coal retirements based on the earliest practicable schedule that can be achieved while preserving the safety and reliability of the system, but it does so without considering the economics of the accelerated coal retirements compared to replacement resources. That schedule is reflected in Portfolios C, D and E.

The Company states that there is no immediate need for decisions to acquire or build new resources in this IRP. However, the Company has indicated in the Short-Term Action Plan that it plans to retire the coal-fired Allen Steam Station ("Allen") Units 2-4 by January 1, 2022, and Units 1 and 5 by January 1, 2024. Thus, those decisions are near-term even if there is no immediate need to replace those existing resources with new resources.

DEC has provided the specific information required by Section B(1) of Act 62. This information is necessary for the Commission to assess the Company's IRP, consider the seven factors set forth in Section C(2) of Act 62, and determine whether the utility's IRP represents the "most reasonable and prudent means of meeting the electrical utility's energy and capacity needs as of the time the plan is reviewed." However, ORS has identified some areas for improvement and provides recommendations that address the IRP process, load and energy forecasts, generic resource profiles, production cost and revenue requirements modeling, and assumptions relied on to develop the portfolios and the resulting comparative metrics, including customer rate impacts. Some of the

[12] https://news.duke-energy.com/releases/duke-energy-aims-to-achieve-net-zero-carbon-emissions-by-2050

recommendations address issues that could be addressed in the form of a modified IRP in this proceeding. These are designated with an "N" to recommend the Company act now to modify the IRP. The others address recommendations that could be addressed in the next annual update IRP later this year (designated with an "L"), but no later than the next comprehensive IRP in 2023. The later recommendations are no less important, but we recognize that the implementation of these could require more time and could benefit from guidance achieved through the stakeholder process.

Load and Energy Forecasts

1. ORS recommends the Company provide a technical appendix that more fully describes each of the models, presents the statistical results and shows the individual energy and peak load forecast results that were actually developed. While DEC's IRP provides an overview of this information, it does not provide the detail necessary to fully evaluate the entire forecast. This detail was provided in response to discovery in this proceeding, however, we recommend this level of detail be included in future IRPs as part of a comprehensive technical appendix. **(L)**

Resource Adequacy – Reserve Margin Issues

2. ORS recommends the Company provide a more detailed discussion of the specific methodology used to develop the synthetic loads for extreme low temperature periods. While the Resource Adequacy Report provides an overview of this issue, it does not provide sufficient detail regarding how the analysis was conducted or what specific additional adjustments were made to the load data at extreme low temperatures. This detail was provided in response to discovery in this proceeding, however, we recommend this level of detail be included in future IRPs as part of a comprehensive technical appendix. **(L)**

3. ORS recommends the Company further develop its methodology to model the effects of extreme low temperatures on winter peak load. Given the significance of this issue, as discussed in the ORS Report, there may be alternative methodologies that the Company could consider to develop its synthetic loads in hours in which the temperatures fall significantly below the temperatures experienced during the weather/load estimation period (i.e., neural net model training period). We recommend this be addressed in future IRPs through the Company's stakeholder process. **(L)**

4. ORS recommends the Company provide a detailed discussion in the IRP Report or appendices that explains how the results of the Astrapé 2018 Solar Capacity Value Study were used to derive the assumed winter peak standalone solar capacity value of 1%. We recommend this information be included in a modified IRP in this proceeding. **(N)**

Energy Efficiency and Demand Side Management

5. ORS recommends the Company provide additional justification for selecting the Base EE/DSM case as opposed to the High EE/DSM case for use in Portfolio A, given that the High EE/DSM case may provide greater customer benefits. We recommend this information be included in a modified IRP in this proceeding. **(N)**

6. ORS recommends that, in addition to the sensitivity cases included in Table A-9, the Company also evaluate high and low levels of EE/DSM using high fuel/CO2 and low fuel/CO2 assumptions. We recommend this information be included in a modified IRP in this proceeding. **(N)**

7. The Company provided no basis for the low EE/DSM forecast that it used in the IRP. The Company's approach may be reasonable; however, it would be a better practice to provide more justification as to how it derived the low EE/DSM forecast. ORS recommends the Company provide additional justification or consider other approaches for deriving the low EE/DSM forecast. We recommend this be addressed in future IRPs through the Company's stakeholder process. **(L)**

Natural Gas Price Forecasts

8. ORS recommends the Company review its natural gas price forecasting methodology and investigate alternative approaches. We recommend this be addressed in future IRPs through the Company's stakeholder process. **(L)**

CO_2 and Other Environmental Issues

9. ORS recommends the Company provide tables summarizing the capital and operations and maintenance ("O&M") costs for compliance with environmental regulations by unit and by environmental regulation, and include descriptions explaining those costs. We recommend this information be included in a modified IRP in this proceeding. **(N)**

Existing System Resources

10. To ensure there are no inconsistencies in modeling data, we recommend the Company create a cross reference table that compares each resource modeled in PROSYM, including generating units, demand response, purchase contracts, sales contracts, EE, etc. to the corresponding data in the Load, Capacity and Reserves ("LCR") table, on a resource by resource basis. We recommend this be developed for both the Base Case with CO_2 and Base Case without CO_2 cases, and cover all of the years in the study period. We recommend this information be provided in a modified IRP in this proceeding. **(N)**

11. Recognizing that the Company plans to pursue relicensing of the Oconee nuclear units' operating licenses in 2021, we recommend the Company supply additional information regarding its relicensing plans (including a timeline) and its plans to conduct economic evaluations to assess the benefits of relicensing the units. We recommend the Company provide additional insight into why it is beginning this process so far in advance of the relicensing dates. We recommend this information be provided in a modified IRP in this proceeding. **(N)**

12. The Bad Creek Pumped Hydro units' licenses are set to expire in 2027. However, the IRP does not provide details on the relicensing status of these units. Since these units will need to go through a relicensing process with the Federal Energy Regulatory Commission ("FERC") soon, we recommend that DEC provide the status of its plans to relicense the units, including any actions it will have to take as part of the relicensing process and any costs that it will incur to relicense the units. We recommend this information be provided in a modified IRP in this proceeding. **(N)**

13. ORS recommends DEC provide additional clarification regarding its plans for the retirement of the Allen units, including details about any transmission impacts, an explanation of the steps being pursued to receive final approval within DEC and from any regulatory body, and a timeline for conducting these activities. We recommend this information be provided in a modified IRP in this proceeding. **(N)**

14. ORS recommends the Company provide evidence that the optimal retirement dates that were determined with the Sequential Peaker Method ("SPM") are comparable to the optimal retirement dates the System Optimizer model would produce if it were used in the retirement study. We recommend this information be provided in a modified IRP in this proceeding. **(N)**

Generic Resource Options

15. ORS recommends the Company supply additional information explaining the basis for how combined heat and power ("CHP") resources were added to the short-term action plan and explain why CHP resources were not treated as selectable resources in the economic optimization process, if in fact they were not. We recommend this information be provided in a modified IRP in this proceeding. **(N)**

16. ORS recommends DEC provide additional justification for its Combustion Turbine ("CT") capital cost assumption. We recommend this information be provided in a modified IRP in this proceeding. **(N)**

17. ORS recommends DEC provide additional justification for its Battery Energy Storage fixed O&M cost and capacity factor assumptions. We recommend this information be provided in a modified IRP in this proceeding. **(N)**

18. ORS recommends the Company include an additional solar generic resource option in its IRP modeling assumptions that reflects the kind of solar purchase power agreements ("PPA") prices that may be available in the market. As a proxy, the Company could assume $38/ megawatt-hour ("MWh") as the solar PPA cost. We recommend this be addressed in a modified IRP in this proceeding. **(N)**

19. Given the importance that solar capacity values and solar plus battery energy storage capacity values potentially could have on the IRP analysis, ORS recommends that further investigation be conducted regarding these values with stakeholder input, discussed as part of a stakeholder engagement process. One investigation that could be performed would be to assess the impact on the Company's base case resource plan if higher winter capacity value ratings were assumed such as 5% for solar and 30% for solar plus battery energy storage. We recommend this be addressed in the future through the Company's stakeholder process. **(L)**

Renewables

20. ORS recommends the Company provide a table identifying each renewable resource option that was modeled, and include whether the resource was forced-in or economically selected (System Optimizer or other approach), the reason the resource was forced-in (e.g. Competitive Procurement of Renewable Energy Program ("CPRE"), Act 236, etc.), whether the resource is a designated, mandated, or undesignated resource, and where the resource is found in the PROSYM database and in the LCR tables for reconciliation purposes. We recommend this information be provided in a modified IRP in this proceeding. **(N)**

Economic Evaluation of Portfolios and Sensitivities

21. ORS recommends the Company include post in-service capital costs for new resource additions in its capital cost model and its Present Value of Revenue Requirement ("PVRR") calculations for each Portfolio and each sensitivity of each Portfolio. We recommend this be addressed in a modified IRP in this proceeding. **(N)**

Customer Rate Impacts

22. The average retail rate impacts are an important consideration when assessing whether Portfolios and the pathways reflected in those Portfolios are reasonable. This should be considered in this IRP and future IRPs, but it does not require a modified IRP in this proceeding. **(N)**

23. ORS recommends the Company revise the calculation of the average retail rate impact on customers so that the assumptions and methodologies are consistent with the calculations of the PVRR, except for the levelization of the capital-related costs. We recommend this be included in a modified IRP in this proceeding. (**N)**

<u>Other Considerations – Action Plan</u>

24. ORS recommends the Company provide additional details and status updates about resources included in the action plan, including coal retirements, the Lincoln CT project, unnamed energy storage projects, nuclear uprates, Bad Creek upgrades, and unnamed CHP projects. We recommend this information be included in a modified IRP in this proceeding. **(N)**

<u>Other Considerations – Southeast Energy Exchange Market (“SEEM”)</u>

25. ORS recommends that in future IRPs, the Company provide details regarding the status of the SEEM, details regarding important current and planned activities, and information regarding the monetary benefits that have been or could be achieved by implementation of the SEEM. We recommend this be addressed in the future through the Company’s stakeholder process. **(L)**

Evolution of the IRP Process in South Carolina

Initiation and Evolution of IRP Process

The Commission initiated a generic proceeding in June 1987 to address least-cost resource procedures based on a comprehensive planning approach for jurisdictional electric utilities.[13] Electric utilities were required to file IRPs in September 1989.[14]

The Commission subsequently approved a more formal IRP process in October 1991.[15] The Commission required utilities to file detailed IRPs every three (3) years and short-term action plans in the intervening years. In addition to the Commission's IRP procedures, the South Carolina legislature passed a bill (Act 449) known as the South Carolina Energy Conservation and Efficiency Act of 1992, adding S.C. Code Ann. § 58-37-40.[16] The definition of an IRP adopted for use in South Carolina is found in S.C. Code Ann. § 58-37-10(2):

> "Integrated resource plan" means a plan which contains the demand and energy forecast for at least a fifteen-year period, contains the supplier's or producer's program for meeting the requirements shown in its forecast in an economic and reliable manner, including both demand-side and supply-side options, with a brief description and summary cost-benefit analysis, if available, of each option which was considered, including those not selected, sets forth the supplier's or producer's assumptions and conclusions with respect to the effect of the plan on the cost and reliability of energy service, and describes the external environmental and economic consequences of the plan to the extent practicable. For electrical utilities subject to the jurisdiction of the South Carolina Public Service Commission, this definition must be interpreted in a manner consistent with the integrated resource planning process adopted by the commission. For electric cooperatives subject to the regulations of the Rural Electrification Administration, this definition must be interpreted in a manner consistent with any integrated resource planning process prescribed by Rural Electrification Administration regulations.

Utilities followed the IRP requirements established by the Commission in its 1991 order until 1998. On February 3, 1998, Duke Energy filed a petition to modify the IRP requirements, which led the Commission to re-evaluate its IRP procedures.[17] On July 2, 1998, the Commission issued Order No. 98-502, which established a simplified set of IRP

[13] Docket No. 87-223-E, Order No. 87-569, June 18, 1987.
[14] Docket No. 87-223-E, Order No. 89-521, May 17, 1989.
[15] Docket No. 87-223-E, Order No. 91-885, October 21, 1991. Attachment A to the Order contained the detailed IRP requirements. Another Order granting clarification and modification was issued on November 6, 1991 (Order No. 91-1002).
[16] www.scstatehouse.gov/billsearch.php?billnumbers=1273&session=109&summary=B
[17] February 3, 1998. Docket No. 87-223-E, Order No. 98-502, July 2, 1998.

requirements based on what the Commission observed at the time to be "the changing nature and deemphasis of Integrated Resource Planning."[18]

The state legislature subsequently passed Act 62 also known as the Energy Freedom Act of 2019, which addressed many issues associated with utility planning, including updating and re-emphasizing IRP requirements.[19]

Most recently, the Commission issued Order No. 2020-832, in which it addressed Dominion Energy South Carolina, Incorporated's ("DESC") IRP, the first IRP filed by an electric utility since Act 62 was enacted. In that Order, the Commission addressed various issues of interpretation and application of those new statutory requirements, some of which may be applicable to DEC and DEP in this proceeding.

Act 62 IRP Requirements

Act 62 was signed into law in May 2019. Act 62 updated Section 40 by changing some requirements and adding others that affected not only the electric utilities, but also the Commission, ORS and the State Energy Office ("SEO"). Act 62 applies to all electric utilities in South Carolina.

Section 40 now requires electric utilities to file IRPs that provide more detailed information to the Commission and other parties, and to post the IRPs on both the Commission and utility's websites. Electric utilities are required to file IRPs at least every three (3) years, and to file annual updates with specific information in the intervening years.[20] Section 40(B)(1) sets forth the required information and Section 40(B)(2) sets forth the additional optional information.

Section 40 now requires the Commission to establish a proceeding to review each electric utility's IRP. Interested parties are permitted to intervene and submit discovery. Section 40(C)(1) states the new requirements are intended to allow interested parties to obtain "evidence concerning the integrated resource plan, including the reasonableness and prudence of the plan and alternatives to the plan."

Sections 40(C)1 and (C)2 state the Commission shall issue a final order within 300 days approving the utility's IRP as is, if the Commission "determines that the proposed integrated resource plan represents the most reasonable and prudent means of meeting the electrical utility's energy and capacity needs as of the time the plan is reviewed." However, if the Commission finds that the IRP does not meet that standard, then the Commission is required to either order the utility to make specific modifications to its IRP or reject the IRP entirely. If the Commission makes one of these determinations, Section

[18] Docket No. 87-223-E, Order No. 98-150, February 25, 1998.
[19] Act 62 became effective on May 16, 2019.
[20] S.C. Code Ann. § 58-37-40(D)(1).

40(C)(3) provides procedures and a timeline that requires the utility to resubmit its IRP and ORS to review the revisions and report its findings to the Commission. Then, the Commission "at its discretion may determine whether to accept the revised integrated resource plan or to mandate further remedies that the Commission deems appropriate."

Section 40(C)2 directs the Commission to consider seven (7) factors as it evaluates whether the IRP is "the most reasonable and prudent means of meeting energy and capacity needs" and determine whether the IRP should be accepted, modified or rejected.

Section 40(D)1 discusses the requirements for IRP updates that are to be filed during the two (2) intervening years between when comprehensive filings are to be made. Section 40(D)2 discusses the procedure for reviewing annual updates, which is different than for the comprehensive filing that utilities must make every three (3) years. For the annual updates, ORS is required to review the utility's filing and submit a report to the Commission containing a recommendation concerning the reasonableness of the annual update. The Commission then must decide if it will "…accept the annual update or direct the electrical utility to make changes to the annual update that the commission determines to be in the public interest."[21]

Commission Consideration of DEC's IRP

The Company notes that the statute "directs the Commission to approve the plan as reasonable and prudent at the time the plan was reviewed by taking into consideration if the plan appropriately balances various criteria addressing reliability, affordability, compliance with environmental regulations, commodity price risk, diversity of supply, and other factors the Commission determines to be in the public interest."[22] The Company asserts that its IRP met that goal.

ORS Approach to Performing this Review

ORS set objectives for the review, analyses and recommendation to determine if the Company met the statutory requirements of Section 40 and to provide a recommendation to approve, modify or reject the Company's IRP. To achieve these objectives, ORS reviewed the Company's IRP, testimony, exhibits, prior IRPs and IRPs filed by other electric utilities, including DESC, Lockhart Power Company, Georgia Power Company, Entergy Louisiana, LLC, PacifiCorp, Kentucky Power Company, and others. ORS also conducted extensive discovery, including six (6) sets with over 79 questions including some multi-part questions, held a technical conference call with the Company on October 30, 2020, participated in an IRP Technical conference hosted by the Company for all intervenors on September 18, 2020, and participated in other stakeholder engagement conference calls that the Company hosted throughout the year. In addition, ORS

[21] S.C. Code Ann. § 58-37-40(D)(2).
[22] Direct Testimony of Glen Snider, pg. 36, ln. 3.

submitted informal questions that requested DEC subject matter experts to review and respond, and reviewed extensive discovery and filings in the parallel North Carolina IRP proceedings.

Compliance with Requirements of Section 40

This section of the Report first addresses the Company's compliance with the specific information requirements listed in the statute (Sections B(1) and B(2)) and then addresses the seven (7) factors set forth in Section C(2) of Act 62 that the Commission is directed to consider in deciding whether the Company's "proposed integrated resource plan represents the most reasonable and prudent means of meeting the electrical utility's energy and capacity needs as of the time the plan is reviewed."[23]

DEC has provided the specific information that addresses Sections B(1) and B(2) of Act 62. ORS has identified opportunities for DEC to improve this IRP and future IRPs, including requesting supplemental information that could assist the Commission in its consideration of the seven factors set forth in Section C(2). In subsequent section of the Report, ORS makes certain recommendations to be reflected in a modified IRP prior to Commission approval in this proceeding and future proceedings and makes additional recommendations for future IRPs.

Statutory Requirements in Section 40(B)

The following section of this Report provides the ORS assessment of the Company's compliance with the Section 40(B)(1) and (2) statutory requirements.

B: An integrated resource plan shall include:

(1)(a): a long-term forecast of the utility's sales and peak demand under various reasonable scenarios.

DEC complied with the requirement to provide a long-term forecast of its sales and peak demand, and provided such forecasts under various reasonable scenarios. The load forecast development process is discussed in Chapter 3 and Appendix C of the Company's IRP report.

(1)(b): the type of generation technology proposed for a generation facility contained in the plan and the proposed capacity of the generation facility, including fuel cost sensitivities under various reasonable scenarios.

DEC complied with the requirements to provide generation technology information for new generic resources considered in its IRP, including each of the six Portfolios. In the IRP report, the Company discusses the various potential new generic resource alternatives that it evaluated, which include combustion turbines ("CTs"), reciprocating engines, combined cycle combustion turbines ("CCGT"), coal, nuclear, CHP, wind, solar photovoltaic ("solar"), other renewables, such as onshore and offshore wind, and battery and other storage technologies. In Appendix G of its IRP Report, the Company discusses the screening

[23] Section 40(C)(1) sets forth the standard of review and Section 40(C)(2) identifies the seven (7) factors.

process that it used to narrow down the resource alternatives. That section includes a table on page 326 that provides a list of generic resources that were evaluated and the capacities of the resources. In confidential Excel workbooks provided in response to discovery, the Company provided significant technical and cost information obtained from various sources that it used to develop capital-related costs and operating expenses for each of the new generic resources. Once it created the six Portfolios, the Company also conducted fuel cost sensitivities as part of its economic evaluation of the Portfolios.

(1)(c): projected energy purchased or produced by the utility from a renewable energy resource.

DEC complied with this requirement by providing information in Section 5 of its IRP Report concerning both renewable resources that were required to meet state statutory and regulatory obligations (predominantly North Carolina statutory and regulatory requirements) and resources that were economically selected over the resource planning period. The Company identified renewable resource additions and capacity amounts by year in Figure 12-F of the IRP Report.

(1)(d): a summary of the electrical transmission investments planned by the utility.

DEC complied with this requirement by providing information in Appendix L of its IRP Report, in which it discussed its planned or currently under construction transmission investments. It also included information in Chapter 7 of its IRP Report about grid requirements, in which it described the development of initial transmission cost estimates associated with the retirement of some of its coal generating units during the study period (planning horizon), and the siting of additional generation resources for the six (6) Portfolios that were confected and modeled. The Company indicated its projection of transmission investments were provided as high-level estimates for each Portfolio because the new resource additions do not have specific site locations at this stage of the planning process. The Company stated, "Extensive additional study and analysis of the complex interactions regarding future resource planning decisions will be needed over time to better quantify the cost of transmission system upgrades associated with any portfolio."[24]

(1)(e): several resource portfolios developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's service obligations. Such portfolios and evaluations must include an evaluation of low, medium, and high cases for the adoption of renewable energy and cogeneration, energy efficiency, and demand response measures, including consideration of the following:

[24] DEC 2020 IRP, Chapter 7, pg. 54.

i. customer energy efficiency and demand response programs;

ii. facility retirement assumptions; and

iii. sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks.

DEC complied with this requirement by developing six (6) specific Portfolios in which it evaluated a range of demand-side, supply-side, storage and other technologies and services that could be relied on to meet its obligations. DEC conducted sensitivity analyses in which it included estimates of low, medium, and high cases related to fuel and CO_2 costs, and EE/DSM to determine the impacts on the portfolios it evaluated.

The Company conducted several studies to guide the development of its IRP, including performing an updated EE market potential study ("MPS"), and a study to examine the potential for additional winter demand-side peak savings through innovative rates initiatives combined with advanced demand response and load shifting programs that went beyond the scope of the MPS. The demand response study is still on-going and the Company states that it "envisions working with stakeholders in the upcoming months and beyond to investigate and deploy, subject to regulatory approval, additional cost-effective programs identified through this effort."[25] The Company also indicated the preliminary study results are promising and show a potential for the Company moving towards the High EE case in the IRP.

With regard to facility retirement assumptions, the Company conducted a retirement analysis that is described in detail in Chapter 11 entitled, Coal Retirement Analysis. The results of the study show that under either the Base Case with or without CO_2 portfolios, it would be economic to accelerate retirement of coal units compared to the projected coal retirement dates that were included in the DEC 2019 IRP. This is important finding because it accelerates the retirement of some of the Allen units to as early as the end of this year.

(1)(f): data regarding the utility's current generation portfolio, including the age, licensing status, and remaining estimated life of operation for each facility in the portfolio.

The Company complied with this requirement by providing data regarding the utility's current generation portfolio in Appendix B, that includes the age and estimated remaining life of its owned existing generating resources. Additional information in that Appendix includes the winter and summer capacity ratings and fuel type for each existing resource, as well as the licensing status of its nuclear and hydro resources.

[25] DEC 2020 IRP, Chapter 4, pg. 36.

(1)(g): plans for meeting current and future capacity needs with the cost estimates for all proposed resource portfolios in the plan.

The Company complied with this requirement by ensuring that each of the six (6) portfolios it evaluated would be able to meet expected capacity requirements, providing detailed cost estimates for all new generic resources included in each Portfolio, and providing the present value revenue requirement ("PVRR") comparisons for all six portfolios based on high, medium and low CO_2 and fuel cost sensitivity cases.[26] The Company also performed sensitivity analyses in which it used the Base Case with CO_2 portfolio and developed comparison cases with high and low levels of renewables, EE, and renewable capital costs. In addition, the Company created sensitivity cases to investigate a shorter operating life assumption for natural gas resources (25 vs 35 years), an increased pumped storage hydro case, and a lower battery storage cost case (capital cost reduced by 15%).

(1)(h): an analysis of the cost and reliability impacts of all reasonable options available to meet projected energy and capacity needs.

The Company complied with the requirement to include an analysis of the cost of all reasonable options by performing both optimization analyses using the System Optimizer Model and production cost analyses using the PROSYM model. Those analyses consider the production costs to operate DEC's generating units including both existing plus future resource additions, and includes capital related revenue requirements based on incremental resource additions to its System. In addition, the company considered cost impacts in another way by considering average retail and residential bill impacts which are useful in assessing customer affordability of the Company's resource plans.

The Company evaluated reliability impacts in several ways. First, DEC contracted with Astrapé Consulting to perform a detailed resource adequacy and reliability study, which determined the appropriate planning reserve margin target for the Company. The planning reserve margin target is critical to determining the appropriate level of resources needed to maintain system reliability. Astrapé also performed a study to determine the effective capacity value of storage resources, which it refers to as the Storage Effective Load Carrying Study. Second, as mentioned the Company conducted production cost analyses using PROSYM. In addition to determining the fuel and O&M costs to operate generating resources, PROSYM also evaluates the reliability of the system by determining the amount of unserved energy that may be expected in any given year for each portfolio and assigns a cost to that energy. ORS concluded that the Company's resource adequacy analyses are reasonable.

[26] DEC 2020 IRP, Table A-15.

(1)(i): a forecast of the utility's peak demand, details regarding the amount of peak demand reduction the utility expects to achieve, and the actions the utility proposes to take in order to achieve that peak demand reduction.

The Company complied with the requirement to provide a forecast of its peak demand, and it provided details regarding the amount of peak demand reduction the Company expects to achieve. Chapter 3 and Appendix C of the IRP report provide information regarding the development of the three retail load forecasts for the Residential, Commercial, and Industrial classes, and explain the key drivers that influence the load forecasts. Chapter 4 and Appendix D of the IRP report provide an overview of the EE and demand-side management programs ("DSM"). DEC includes DSM programs, also referred to as demand response programs, for both residential and non-residential customers, though the programs to date have mostly been geared towards controlling summer peak demand. The Company also recognizes the importance of controlling winter peak demand, and as such has commissioned a study to specifically examine the potential for additional winter demand-side peak savings through innovative rates initiatives combined with advanced demand response and load shifting programs. The Company has engaged Tierra Resource Consultants, who collaborated with Dunsky Energy Consulting and Proctor Engineering to perform the study. The consultant's study was not completed at the time DEC filed its IRP; however, the Company discussed that when the results are available it will work with stakeholder to further develop the programs identified in the study.

(B)(2): An integrated resource plan may include distribution resource plans or integrated system operations plans.

The Company has addressed this optional requirement and describes distribution resource plans most significantly in Chapter 15, where it discusses plans for Integrated System & Operations Planning ("ISOP"). The Company believes this effort will be important "to address the trends in technology development, declining cost projections for energy storage and renewable resources, and customer adoption of electric demand modifying resources such as roof-top solar and electric vehicles ("EV"s)."[27] According to DEC, the reason more advanced distribution planning is necessary is to be able to better analyze the distribution and transmission systems in order to account for increasing variability of generation and two-way power flows on the distribution system, which will require significant changes to modeling inputs and tools. The Company states that it is committed to implementing ISOP planning in the 2022 IRP.

In addition, in Chapter 4 of the IRP the Company discussed its plans for implementing Integrated Voltage/VAR Control ("IVVC"), which it states is part of the proposed Duke

[27] DEC 2020 IRP, pg. 124.

Energy Carolinas Grid Improvement Plan and involves the coordinated control of distribution equipment in substations and on distribution lines to optimize voltages and power factors on the distribution grid.

Statutory Requirements in Section 40(C)(2)

The statute directs the Commission to consider seven (7) factors in making its determination as to whether the IRP "represents the most reasonable and prudent means of meeting the electrical utility's energy and capacity needs at of the time the plan is reviewed." The following are the factors that must be considered:

C(2): The commission, in its discretion, shall consider whether the plan appropriately balances the following factors:

(a) resource adequacy and capacity to serve anticipated peak electrical load, and applicable planning reserve margins.

(**b) consumer affordability and least cost.**

(c) compliance with applicable state and federal environmental regulations.

(d) power supply reliability.

(e) commodity price risks.

(f) diversity of generation supply.

(g) other foreseeable conditions that the commission determines to be for the public interest.

The Commission is required to consider these seven (7) factors in evaluating whether it believes that DEC's IRP "represents the most reasonable and prudent" means of meeting its capacity and energy requirements, and in doing so the Commission is permitted to use its discretion to judge the factors that it believes should receive a greater decision making weighting compared to the other factors. The Commission recently issued its order in DESC's 2020 IRP (Order No. 2020-832) in which it stated that it was providing "guidance on its interpretation and expectations for compliance with the statute for the public interest not only for DESC, but also for other electrical utilities."[28]

The Commission provided additional guidance on the standard that a utility's IRP must meet and the factors that the Commission will use to evaluate a utility's IRP, as follows:

- **Reasonable** – "the plan must be 'reasonable,' meaning it is rational, logically consistent, and the result of sound judgment. In the context here, this requires

[28] December 23, 2020, Commission Order No. 2020-832, Docket No. 2019-226-E, pg. 7.

consideration of whether the utility's plan meets the requirements of Act 62 and comports with industry norms and widely-known IRP best practices." [29]

- **Prudent** – "it gives due consideration to actual and foreseeable future conditions and risks. Such consideration should take into account the relative costs and benefits of avoiding potential future risks, such as regulatory, capital, or fuel risks."[30]
- **Detailed Information** – "the IRP and the record must provide sufficient information about each of the seven balancing factors to enable the Commission to determine if the IRP appropriately balances each of them. Act 62 also requires that the plan must represent the most reasonable and prudent means of meeting the electrical utility's energy and capacity needs as of the time the plan is reviewed."[31]
- **Best Available Tools and Modeling Capabilities** – "This is a significant standard that implies that IRP requirements should not be static, but rather should continuously improve over time as standards and practices improve and evolve. It also implies that a utility may not do the bare minimum, but rather must ensure that its IRP is the result of serious planning and consideration using the best available data and tools available to it."[32]
- **Risk** – "Act 62 requires that the Commission balance a number of factors, including "commodity price risks" and "diversity of generation supply."[33]

The Commission emphasized that although cost is an important consideration, "reasonableness" and "prudence" do not require that the utility simply select the least-cost resource plan, given the inherent uncertainty of sensitivity assumptions for future conditions.

These are guidelines for the evaluation of a utility's IRP and balancing the statute's seven (7) specific factors. As previously noted, DEC evaluated six (6) portfolios designed to consider regulatory/environmental, capital cost, and commodity price risks. The Company conducted a detailed coal retirement study and produced an economic coal retirement schedule as well as a more aggressive coal retirement schedule based on the earliest possible dates that coal units could be retired. The Company conducted evaluations of low, base, and high levels of renewable resources, and EE, all of which provide relevant insight into the path forward, the options it could pursue in the future, and whether that path forward provides sufficient flexibility to allow the utility to alter its course as conditions change.

With regard to the question of whether DEC has provided the necessary information

[29] *Id.* pg. 12.
[30] *Id.* pg. 13.
[31] *Id.* pg. 13.
[32] *Id.* pg. 13.
[33] *Id.* pg. 14.

required by Section 58-37-40(B), DEC did comply with all of the requirements of Section 40(B). However, as noted in this Report, there are improvements that could be made to DEC's IRP. ORS concluded that many of the issues raised could be addressed immediately or in the near future working under the guidance of the stakeholder process.

With regard to the items that the Commission discussed in the DESC order, based on the evaluation of DEC's IRP, ORS concluded that DEC conducted a thorough IRP evaluation. The Company relied on industry standard approaches, such as using optimization modeling tools, performed stochastic based reliability analyses, used load forecasting and production cost modeling tools that are widely used in the industry, and retained industry experts to conduct various analyses that were either integral to its current IRP study (e.g., Nexant, Inc. produced an EE MPS), or will be in the near future (Tierra Resource Consultants conducted a demand response study). In addition, the Company demonstrated that it is currently developing new modeling approaches that will likely lead to further integration of transmission and distribution planning (ISOP) with its current supply-side and demand-side planning processes, and its current plan is to utilize and integrate these new tools in developing its 2022 IRP.

In the six Portfolios evaluated, the Company demonstrated that it evaluated a wide range of resource alternatives, including many advanced resource alternatives including small modular nuclear reactors and offshore wind. The Company developed two base cases; one that reflects the regulatory and statutory requirements that exist today, without consideration of CO_2, and another that includes consideration of CO_2 policy. One issue in this proceeding is whether DEC has included an appropriate level of renewable resources in its preferred resource plan, which DEC has identified to be its Base Case without CO_2 plan.

In the Base Case without CO_2 plan, DEC included 1,981 MW of base solar, 739 MW of base solar plus storage and 161 MW of base battery energy storage. This is significant and could increase in future IRPs as statutory, regulatory, and other circumstances change.

In the Base Case with CO_2 plan, the Company explicitly recognizes the possibility that a CO_2 policy will be implemented, essentially providing a risk adjusted plan that overlays this possibility on the Base Case without CO_2 plan. In the Base Case with CO_2 plan, DEC included the same amount of base solar and solar plus storage, but also economically selected an additional 1,275 MW of solar, 975 MW of solar plus battery storage capacity and 150 MW of offshore wind to the portfolio. While there is an increase in renewable resources over the planning horizon in the Base Case with CO_2 plan, CCGT capacity is the same, but there is a 914 MW reduction in the amount of CT capacity added.

At this time, DEC supports the Base Case without CO_2 case as its preferred plan for purposes of avoided cost proceedings, value of solar calculations, cost-effectiveness, and DSM evaluations.[34] It is likely that they choose this plan because 1) it reflects currents regulatory and statutory policy that is in place today, 2) it represents the least cost plan under current policy assumptions, 3) it includes a considerable amount of new renewable resources, 4) it relies on resources that are commercially available today, and 5) it is a flexible plan that can easily be modified to allow more renewable resources to be added if a CO_2 policy is implemented.

However, the Base Case with CO_2 case offers the advantages of including additional amounts of solar and solar plus battery storage capacity, and is based on resource types that are commercially available today. Note, however, that the premise of the Base Case with CO_2 plan is that CO_2 policy will be implemented someday, yet the date when the CO_2 policy would begin and the cost associated with that policy, such as a CO_2 tax, is highly uncertain and may not be known for some time.

[34] ORS AIR 3-1, part d.

Evaluation of DEC's IRP

Load and Energy Forecast

Overview

This section of the report discusses the Company's 2020 IRP load (peak demand) and energy forecasts, both of which are essential elements of a least cost resource plan. ORS reviewed the methodology, models, and forecast results to determine if they are reasonable and meet the requirements of Act 62, Section 40; specifically, Section 40B(1)(a). As discussed below, ORS determined that the forecasts meet the requirements of Act 62, are reasonable, and represent a high level of methodological sophistication. DEC's load and energy forecasts cover the 15-year period 2021 through 2035. During the forecast period, the Company projects an average annual growth rate of 0.7% in energy requirements, and average annual growth rates of 0.9% in summer and 0.7% in winter peak loads. Each of the forecasts reflect embedded energy efficiency (EE), adjusted to reflect roll-offs of EE program impacts as they reach their expected termination date. Incremental (new) EE is then reflected as a separate adjustment to the peak load forecast. The peak load forecasts do not include demand reductions that can be called by the Company pursuant to demand side management ("DSM"). DSM is reflected as a capacity resource in the IRP.

Forecast Analysis

The Company develops econometric based models to forecast energy sales to the residential, commercial, and industrial classes. For the residential and commercial classes, DEC develops average kilowatt-hour (kWh) use per customer models using a statistically adjusted end-use ("SAE") methodology and a separate projection of the number of customers. These types of models incorporate a significant amount of detailed information on customer end-uses (e.g., HVAC equipment, household appliances, commercial building characteristics) that permit modeling of end-use efficiency improvements during the forecast horizon, both those due to federal or state mandates and those due to economic factors and technological innovation. These types of SAE models, in theory, provide a more precise measure of the behavioral factors that influence customer usage. Projections of the number of customers is driven by population projections.

For the industrial sector, the Company uses traditional econometric models in which usage is driven by manufacturing activity indices (Industrial Production Index) and the price of electricity.

Tables 1 to 3 below present the econometric models used by the Company to forecast residential, commercial, and MWh sales. The residential and commercial forecasts are derived based on complex models that incorporate three composite variables (e.g., heating, cooling, other), plus indicator variables that provide a differentiation for each month. The detailed end-use saturation and efficiency data, electric price and income variables are contained in each of the composite variables. The models are estimated using monthly data for the period January 1, 2011 through December 31, 2019. As can be seen from the model statistics in Tables 1 and 2, the R-Squared (R^2) results indicate that the models explain about 90%, or more, of the variation in average use per customer over the 120-month estimation period. In addition, the t-statistics on the key driving variables are high for the residential model, and reasonable for the commercial model.

Table 1
Residential Use Per Customer Model

Adjusted Observations	108
Deg. of Freedom for Error	88
R-Squared	0.939
Adjusted R-Squared	0.926

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
mStruct_RES_SPR20.XHeat1_B	0.002	0	25.701	0.00%	End-use Heating
mStruct_RES_SPR20.XCool1_B	0.002	0	32.128	0.00%	End-use cooling
mStruct_RES_SPR20.XOther_B	0.002	0	74.111	0.00%	End-use non-weather sensitive
mIndicators.FEB11	-0.224	0.063	-3.552	0.06%	
mIndicators.JUN11	0.263	0.061	4.304	0.00%	
mIndicators.JUN12	0.168	0.061	2.739	0.75%	
mIndicators.JUL12	0.177	0.062	2.867	0.52%	
mIndicators.JUN13	0.125	0.061	2.037	4.47%	
mIndicators.DEC13	0.194	0.061	3.166	0.21%	
mIndicators.JUN14	0.171	0.061	2.789	0.65%	
mIndicators.DEC14	0.24	0.061	3.919	0.02%	
mIndicators.JUN15	0.231	0.061	3.783	0.03%	
mIndicators.JUL15	0.126	0.062	2.035	4.48%	
mIndicators.JUN16	0.192	0.061	3.138	0.23%	
mIndicators.FEB17	-0.168	0.061	-2.732	0.76%	
mIndicators.JUN17	0.131	0.061	2.145	3.47%	
mIndicators.JAN18	0.183	0.063	2.903	0.47%	
mIndicators.FEB18	-0.155	0.063	-2.47	1.54%	
mIndicators.JUN18	0.218	0.061	3.566	0.06%	
mIndicators.JUN19	0.128	0.061	2.09	3.95%	

Table 2
Commercial Model

Adjusted Observations	108
Deg. of Freedom for Error	92
R-Squared	0.898
Adjusted R-Squared	0.882

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
CONST	848245	281835	3.01	0.34%	Constant term
mStruct_COM_SPR20.XHeat_B	2993787	1305963	2.292	2.42%	End-use Heating
mStruct_COM_SPR20.XCool_B	1954762	88551	22.075	0.00%	End-use cooling
mStruct_COM_SPR20.XOther_B	92204	19020	4.848	0.00%	End-use non-weather sensitive
mIndicators.FEB11	-206895	91866	-2.252	2.67%	
mIndicators.MAR11	-231130	89245	-2.59	1.12%	
mIndicators.JUN15	247955	89502	2.77	0.68%	
mIndicators.DEC15	-244277	89287	-2.736	0.75%	
mIndicators.JUN16	199790	89419	2.234	2.79%	
mIndicators.MAR17	-190225	89450	-2.127	3.61%	
mIndicators.MAY17	-285605	90156	-3.168	0.21%	
mIndicators.MAR18	-195228	89787	-2.174	3.22%	
mIndicators.JUN18	261787	89988	2.909	0.45%	
mIndicators.SEP18	472617	90832	5.203	0.00%	
mIndicators.OCT18	-256733	90269	-2.844	0.55%	
mIndicators.MAR19	-198795	90370	-2.2	3.03%	

For the industrial model, shown in Table 3, which is a generally standard type of industrial sales econometric model, the R^2 is somewhat lower than reported for the residential and commercial models, indicating that the model explains about 80% of the variation of monthly industrial sales over the 120-month estimation period. All of the driving variables (e.g., industrial production) are reported to be statistically significant.

Table 3
Industrial Model

Adjusted Observations	108
Deg. of Freedom for Error	88
R-Squared	0.825
Adjusted R-Squared	0.787

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
CONST	1517111.1	333588	4.548	0.00%	Constant term
ECON_SPR20.Industrial_Production_Index_Consensus	3869.6	2663	1.453	14.98%	North Carolina Industrial Production Index
SALES_B_IND.Price_L	-28734.9	16788	-1.712	9.05%	Industrial Prices, lagged 7 months
mBilledWeather.JUL_CDD65	296.7	74	4.019	0.01%	CDD Base 65 for July
mBilledWeather.AUG_CDD65	573.6	66	8.706	0.00%	CDD Base 65 for August
mBilledWeather.SEP_CDD65	570.7	84	6.809	0.00%	CDD Base 65 for September
mIndicators.JAN12	-208008.6	78588	-2.647	0.96%	
mIndicators.JAN13	-180076.6	77717	-2.317	2.28%	
mIndicators.JAN14	-174843.9	77476	-2.257	2.65%	
mIndicators.JUN14	195082.0	77507	2.517	1.36%	
mIndicators.JUN15	268248.6	77566	3.458	0.08%	
mIndicators.NOV15	445115.0	77582	5.737	0.00%	
mIndicators.DEC15	-356659.5	77594	-4.597	0.00%	
mIndicators.JUN16	185221.3	78197	2.369	2.00%	
mIndicators.OCT16	145984.3	77631	1.88	6.34%	
mIndicators.APR17	446603.0	78101	5.718	0.00%	
mIndicators.MAY17	-255712.2	77434	-3.302	0.14%	
mIndicators.SEP18	491436.2	83738	5.869	0.00%	
mIndicators.OCT18	-404889.2	78934	-5.129	0.00%	
mIndicators.JAN19	-202479.5	78740	-2.571	1.18%	

Table 4 presents the peak load econometric model that is used to forecast both the summer and winter peaks. Like the residential and commercial models, the peak load model is estimated using monthly data and is primarily driven by composite variables reflecting cooling load, heating load and non-weather sensitive load. The composite variables consist of heating and cooling residential and commercial sales during the maximum combined month (i.e., MWh sales the month in which the maximum combined residential and commercial sales occur in the year). The non-weather sensitive composite variable consists of industrial sales and other sales. This type of model structure provides a link between the Company's electric sales forecast and the summer/winter peak load forecast and incorporates the end-use saturation and efficiency information that is modeled in the residential and commercial sales forecasting models. The statistical results presented for the peak load model indicate the model explains about 80% of the variation in peak load over the estimation period, which is 2013 to 2019.

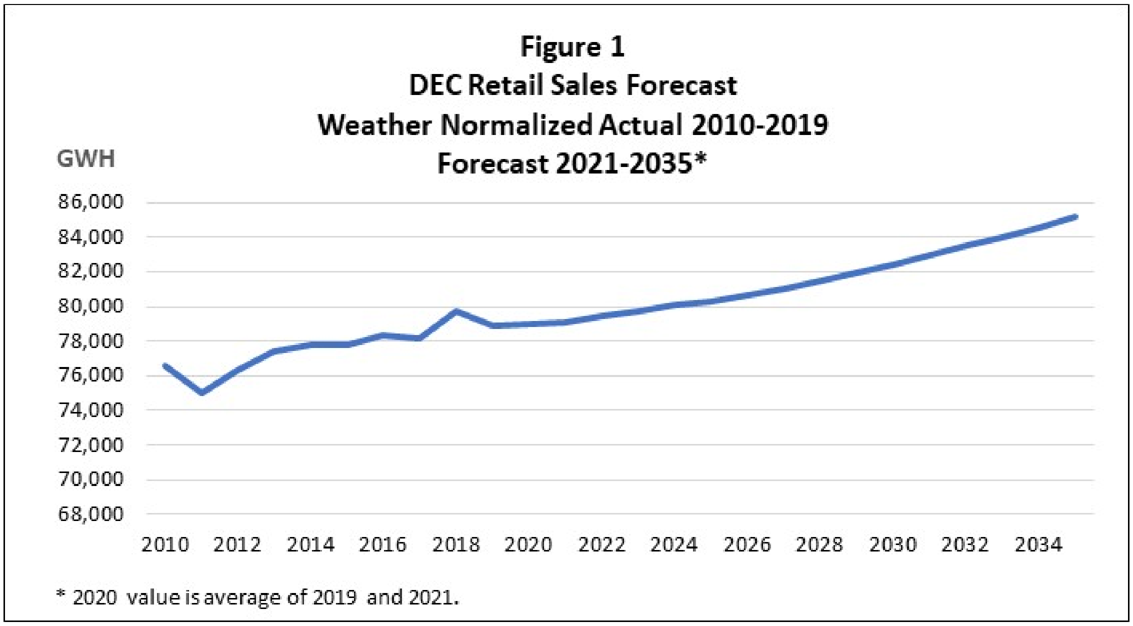
Table 4
Summer/Winter Peak Load Model

Adjusted Observations	96
Deg. of Freedom for Error	87
R-Squared	0.831
Adjusted R-Squared	0.816

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
mPkEndUse_SPR20.CoolVar	233.7	19	12.033	0.00%	Peak End-use cooling
mPkEndUse_SPR20.HeatVar	102.2	13	8.114	0.00%	Peak End-use Heating
mPkEndUse_SPR20.BaseVar	0.0	0	43.554	0.00%	Peak End-use non-weather sensitive
mIndicators.JAN14	1716.3	755	2.272	2.56%	
mIndicators.FEB15	1431.5	758	1.888	6.24%	
mIndicators.NOV15	-1430.0	731	-1.957	5.36%	
mIndicators.MAR17	2146.7	726	2.958	0.40%	
mCalendar.Apr	-959.3	285	-3.366	0.11%	
mCalendar.Oct	-1143.4	286	-4.002	0.01%	

Figure 1 shows the Company's Retail MWh sales forecast for the IRP planning period of 2021 through 2035, together with weather normalized historical retail sales for the period 2010 through 2020.[35] Because wholesale contract requirements changed periodically during the historic period, ORS focused on retail sales (total energy sales less wholesale sales). During the 10-year period through 2019, total weather normalized retail sales grew at only 0.34%, while the Company projects sales growth over the next 15 years to be 0.53%.[36] Essentially, during the past 10 years, DEC has had no retail sales growth. During the forecast horizon, the Company is projecting retail sales growth, primarily in the residential sector.

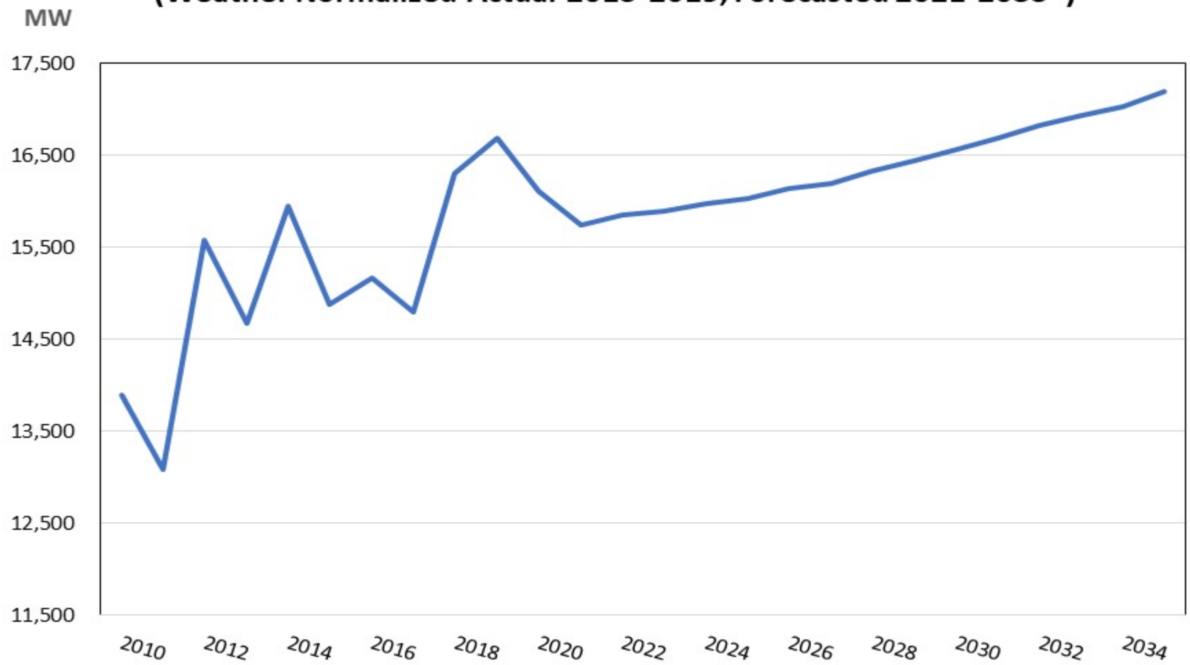
[35] The value for 2020 is calculated as the average of 2019 and 2021.
[36] The forecasted MWh sales do not include the effects of incremental EE programs.



For resource planning purposes, the winter peak demand forecast is the most significant factor. Figure 2 shows the Company's winter peak load forecast, excluding wholesale load, over the IRP planning period of 2021 through 2035, together with corresponding weather normalized historical peaks for the period 2010 through 2020.[37] During the 2010 through 2019 period, winter peak load, excluding wholesale load, grew at 2.1% per year on average, while the Company projects the winter peak load, excluding wholesale load, to grow by 0.6% over the next 15 years.

[37] The value for 2020 is calculated as the average of 2019 and 2021.

Figure 2
DEC Winter Peak Load - Excluding Wholesale
(Weather Normalized Actual 2015-2019, Forecasted 2021-2035*)



* 2020 value is the average of 2019 and 2021

ORS evaluated the performance of the Company's recent sales and winter peak load forecast on the basis of one-year ahead forecast errors. While a 15-year IRP forecast represents a long-term planning forecast, forecast errors on a one-year ahead basis provide some measure of the performance of the forecasts over a longer term. In particular, given the likely forecast errors associated with the key driving variables, such as income and industrial production, evaluation of a one-year ahead forecast error provides information about the performance of the forecasting models themselves, rather than the performance of the driving variables. Table 5 summarizes the one-year ahead retail energy forecasting error for the period 2014 through 2019. The forecast error is calculated as the percentage difference between the forecast for the next year compared to the weather normalized actual retail energy sales for that year. For example, the retail energy sales forecast prepared in 2014 for 2015 is compared to the weather normalized actual retail energy sales for 2015. Over the six-year period, the average one-year ahead energy forecast error for DEC is an over-forecast of 0.6%. On a combined DEP/DEC base, the average retail energy forecast error is an over-forecast of 0.8%.

Table 5
DEC One-Year Ahead Retail Energy Forecast Error

Year IRP Forecast Prepared	Forecast Year	Weather Normalized Actual Retail Sales (GWH))	IRP Forecasted Retail Sales (GWH)	Over/(Under) Forecast (GWH)	One-Year Ahead Forecast Error (%)
2014	2015	77,807	78,150	344	0.4%
2015	2016	78,302	78,925	624	0.8%
2016	2017	78,129	78,714	586	0.7%
2017	2018	79,678	78,124	(1,554)	-2.0%
2018	2019	78,894	79,262	368	0.5%
2019	2020	71,242	73,750	2,508	3.4%
Average					0.6%

* Data through November 2020
Source: Response to ORS 4-4

Table 6 summarizes the one-year ahead winter peak load forecasting error for the period 2014 through 2019. Over the six-year period, the average one-year ahead winter peak load forecast error for DEC is an over-forecast of 1.5%. While this appears to be relatively high, when this result is coupled with the same average one-year ahead winter peak forecast error for DEP, the combined system one-year ahead becomes a 1% under-forecast.

Table 6
DEC One-Year Ahead Winter Peak
Forecast Error

Year IRP Forecast Prepared	Forecast Year	Weather Normalized Actual Winter Peak (MW)	IRP Forecasted Winter Peak (MW)	Over/(Under) Forecast (MW)	One-Year Ahead Forecast Error (%)
2014	2015	17,294	17,303	9	0.1%
2015	2016	17,305	17,896	591	3.3%
2016	2017	16,908	18,416	1,508	8.2%
2017	2018	18,783	18,687	(96)	-0.5%
2018	2019	18,548	17,776	(772)	-4.3%
2019	2020	18,038	18,460	423	2.3%
Average					1.5%

Source: Response to ORS 4-5

Section 40B(1)(a) requires that a utility include a long-term forecast of the sales and peak demand under various reasonable scenarios. In addition to its base load and energy forecast, the Company also developed high and low case forecasts in order to evaluate the effects of alternative economic projections on the IRP resource expansion plans. These high and low case forecasts are based on alternative economic projections by Moody's Analytics.[38] In addition, the Company evaluated the impacts on IRP resource expansion plans from alternative scenarios of EE, DSM and EV penetration.

Conclusions – Load and Energy Forecasts

Based on the review of the Company's methodologies, models and independent assumptions regarding future population growth, economic activity, and end-use efficiency, ORS concluded that the load and energy forecasts are reasonable. Though the Company is projecting future MWh and peak load growth to be greater than the historic period (see Figures 1 and 2), ORS concluded that the forecasts are reasonable. The Company's methodology is reasonable and reflects a high level of sophistication. Notwithstanding this, we recommend the IRP Report include additional detail regarding the specific models and statistical results that underlie the Company's energy sales and peak load forecasts. While the IRP Report contains a technical appendix that discusses the forecast methodology and results, the appendix does not present the actual econometric models used to develop the forecasts. In particular, the Company's models

[38] IRP Report, Appendix A.

incorporate multiple composite variables that represent the main drivers of the forecasting models (e.g., electric price, income, end-use saturation, and efficiency). Even in response to discovery, the Company did not initially provide this detailed information. While this level of detail is not needed in the IRP Report itself, we recommend the Company enhance its load and energy forecast appendix to include a more comprehensive presentation of its forecasting methodology.

ORS concludes that the Company's load and energy forecast complies with the requirements of Section 40, as amended by Act 62.

Recommendations – Load and Energy Forecasts

1. ORS recommends the Company provide a technical appendix that more fully describes each of the models, presents the statistical results and shows the individual energy and peak load forecast results that were actually developed. While DEC's IRP provides an overview of this information, it does not provide the detail necessary to fully evaluate the entire forecast. This detail was provided in response to discovery in this proceeding, however, we recommend this level of detail be included in future IRPs as part of a comprehensive technical appendix. **(L)**

Resource Adequacy – Reserve Margin Issues

Overview

This section of the ORS Report addresses the Company's resource planning reserve margin, which drives, to a large extent, the need for generating resources in the 2020 IRP. The Company's resource adequacy analysis for the 2020 IRP was performed by Astrapé Consulting using its Strategic Energy and Risk Valuation Model ("SERVM"). SERVM is used by Astrapé to develop both the loss of load expectation ("LOLE") based reserve margin calculations and the economically optimal reserve margins. SERVM models each of the key factors that impact reliability – the ability of the Company's generating resources at various reserve margins to meet customer load without exceeding the 1 day in 10-year LOLE criterion. These key factors include:

1. The effect of temperature on load and the historic temperature distribution.
2. Generator outage characteristics, including the effect of extreme cold weather on generator availability.
3. The distribution of likely errors in the peak load forecast (other than errors related to weather, which is reflected in item 1 above.)
4. The amount of tie-line MW support that can be imported from neighboring systems ('market assistance') during emergencies.

The model performs multiple Monte-Carlo simulations reflecting random outcomes of these factors to estimate the LOLE for a range of reserve margins.[39] The SERVM analysis is performed for a single base year of 2024. The final reserve margin is determined by identifying the LOLE needed to achieve the 1 day in 10-year criterion.

DEC proposes to utilize a planning reserve margin of 17% for the winter peak and 15% for the summer peak over the IRP planning period 2021 to 2035. This is consistent with the Company's reserve margin targets established in the 2016 IRP. The constraining criterion used for resource planning is the winter peak. In other words, if the Company has sufficient capacity resources to meet the winter reserve margin target, it will also meet the summer reserve margin target. Though the Company's 2020 Resource Adequacy Study showed that DEC required a 16.0% winter peak reserve margin to meet a 1 day in 10-year loss of load expectation ("LOLE"), DEC has used a 17% reserve margin in the 2020 IRP based on the results of a combined DEP/DEC resource adequacy analysis that showed that a joint system 16.75% winter reserve margin would be adequate to meet the 1 day in 10-year LOLE criterion. It is important to note that the 16.0% reserve margin assumes that the Company will have access to emergency capacity from other interconnected utilities (Astrapé refers to this as market assistance). This is a reasonable assumption in this type of resource adequacy analysis. The winter reserve margin needed to achieve an LOLE of 1 day in 10-years without any tie-line support from interconnected utilities is 22.5%. In the Base case, which assumes external market tie-line support, all of the loss of load occurs during the four winter months of December, January, February, and March. There are "0" loss of load events in the other eight months during the year as long as the winter reserve margin is 13% or greater.

The Company also presents economically optimal reserve margin calculations for both the summer and winter peak periods. These economically optimal reserve margins are determined using a least cost methodology that considers the tradeoff between the cost of providing reserves in terms of additional simple cycle combustion turbine capacity and production costs, versus the cost to customers of failing to meet customer load (customer outage costs). The analysis is similar to the basic LOLE analysis but includes these economic costs and benefits in the determination of a target reserve margin. Based on the optimal economic reserve margin analysis, the optimal winter peak reserve margin is only 15.0%. As explained by Astrapé in its report (page 12), the reason for the very low economically optimal winter peak reserve margin is that there are very few hours during the winter period when loads are not met with a low level of reserves. While a 15.0% winter period reserve margin would result in inadequate resources when considered

[39] The model performs a separate Monte-Carlo simulation for 8 selected reserve margins ranging from 8% to 24%. These results are then used to develop a regression model relating winter peak reserve margins and LOLE that provides a full range of possible results over the range of 8% to 24%. The regression curve essentially is used to interpolate the results between the tested reserve margin levels.

based on a strict reliability evaluation, in other words, just considering LOLE results, there would be relatively few hours during the winter that would be affected. At the same time, a 15.0% winter reserve margin would provide sufficient reserves (16.8%) in the summer to avoid a high level of outages during many more hours. The optimal economic reserve margin weighs this winter cost of failing to meet customer needs for a relatively few hours to the cost of additional CT capacity to avoid these customer outages. Since the customer outage cost in the summer period is relatively small, the net effect is a low 15.0% winter peak reserve margin target. Of course, this means that there would be hours during the winter period when customer outages could occur. Based on the LOLE analysis, a 15% winter period reserve margin would result in an LOLE of 0.12, meaning a loss of load expectation of 1 day every 8.3 years, versus a traditional 1 day in 10-year criterion.

Both Astrapé and DEC rely on the results of the LOLE analysis using a 1 day in 10-year criterion, rather than the economically optimal reserve margin results. ORS agrees with this position for a number of reasons. First, our experience with other utilities is that meeting the 1 day in 10-year LOLE target is considered a minimum reserve margin criterion, even if an optimal reserve margin analysis is performed. For example, Southern Company, which also performs an economically optimal reserve margin analysis, uses the LOLE results as a floor. If the economically optimal reserve margin exceeds the LOLE 1 day in 10-year result, then the economically optimal reserve margin would be favored. If, as in the case of DEC, the economically optimal reserve margin is lower than the level that would achieve an LOLE of 1 day in 10-year level of reliability, the higher LOLE based result is used.

Detailed Resource Adequacy Review

ORS reviewed the Company's 2020 Resource Adequacy Study and the associated workpapers provided by the Company in response to discovery. While we reviewed both the basic LOLE analysis and the economically optimal reserve margin study, our primary focus was on the LOLE analysis because 1) this is the analysis relied on by the Company in the 2020 IRP, and 2) the results of the optimal economic reserve margin analysis are not consistent with a reasonable level of reliability for a utility, such as DEC that is not part of a larger regional transmission organization.

As discussed above, the SERVM model is used to perform both analyses. The optimal economic reserve margin study includes two additional components beyond those modeled in the LOLE analysis. These additional components are: 1) the cost to customers of outages and 2) the revenue requirement cost to provide alternative various levels of reserve capacity - primarily reflecting combustion turbine capital costs, production costs and emergency power costs. While the second of these, the cost associated with various levels of reserve capacity is readily straightforward because it relies on production cost analysis and the revenue requirements of combustion turbine capacity, the cost of customer outages is highly uncertain because it relies on customer surveys to broad-based rate classes (residential, commercial, industrial) that ask these customers to state the costs of power outages of varying durations at various seasons of the year. From a big-picture perspective, a reserve margin based on meeting the industry standard of 1 day in 10-years is simply the reserves needed to meet a long-held agreed to level of reliability, without looking at the costs or benefits of doing so. The criterion is simply based on answering the question, what level of reserves are needed to meet this standard. The economically optimal methodology goes beyond this and attempts to answer the question, what level of reserves do customers desire recognizing that they have to pay more to achieve higher levels of reliability. This framework examines the tradeoff between the cost of reserves versus the benefits of those reserves. Theoretically, the economically optimal method is rational – it provides customers with the level of reliability that they are willing to pay for, based on their cost of not having this reliability (for example, lost manufacturing production or spoiled food). The problem, as noted above, is the measurement of this value to customers. The LOLE method, on the other hand, does not address this value issue. Rather, it assumes that there is a minimum level of reliability that customers demand or insist upon. Capacity reserves are added to achieve this level, without actually asking customers if they are receiving value from this level of reliability commensurate with the cost of achieving it. This is similar to transmission planning, when performed strictly to meet reliability criteria.

Common to both analytical frameworks are the major inputs into SERVM of load curves reflecting 39 years of weather experience, forced outage rates of generating resources, especially during extreme cold weather events that impact the ability to serve load during winter peaks, the assumed distribution of load forecasting errors on peak loads and the assumed tie line support in MW provided by neighboring utility systems.

ORS reviewed the Company's modeling and assumptions for each of these inputs. The SERVM analysis is performed for a single year (2024) under 39 possible weather years (1980-2018). A model is estimated to develop the relationship between hourly load and weather using load and weather data for the five-year period January 2014 to September 2019.[40] These load shapes are then scaled to conform to the Company's 2024 load and energy forecast. This produces 39 sets of 2024 hourly load shapes reflecting weather conditions that have occurred in the past 39 years. The SERVM analysis assumes that each of the 39 years of historic weather (1980 to 2018), and the corresponding hourly load has an equal chance of occurring.

There are a number of concerns raised by this type of analysis. First, there is the issue of whether it is reasonable to assume an equal probability of each weather year occurring.

[40] The model is developed using a neural net modeling approach that identifies the most important weather attributes impacting hourly loads.

More specifically, whether more recent weather patterns are more likely due to climate change. The SERVM analysis assumes that the weather in each year over the past 39 years reflects sample observations from a static weather population. This issue has a significant impact on the outcome of the analysis, as we will discuss. Specifically, the lowest temperature that occurred during the model development period (2014 – 9/2019) for the DEC analysis was 6 degrees, while the lowest temperature among the 39-year weather years was minus 5 degrees. The model development period (the neural net training period) did not have low temperature observations consistent with the low temperatures that occurred in some of the 39 weather years. This has an impact on the ability of the model to accurately simulate the 2024 loads for these weather years when such low temperatures occurred. To address this potential problem, Astrapé developed simple linear regression models to estimate the load impact at extreme low temperatures. The regression model (shown in Table 7) for DEC winter mornings consisted of using only 10 observations. The model was estimated using the same training period data base (2014 – 9/2019) as was used to develop the neural net model. The cold weather regression model (Table 7) has an R^2 of 0.95, which means the model explained 95% of the variability in load as a function of temperature.

Table 7
DEC Cold Weather Load Regression

Regression Statistics				
Multiple R	0.976087408			
R Square	0.952746627			
Adjusted R Square	0.946839956			
Standard Error	254.3972319			
Observations	10			
ANOVA				
	df	*SS*	*MS*	*F*
Regression	1	10439011.1	10439011.1	161.3000851
Residual	8	517743.6126	64717.95158	
Total	9	10956754.71		
	Coefficients	*Standard Error*	*t Stat*	*P-value*
Intercept	20298.8886	243.8900203	83.22968103	4.84382E-13
Temp	-216.603102	17.05482917	-12.70039705	1.38985E-06

It is important to recognize that, because the model specification is linear, it is assumed that load will continue to increase as temperatures drop. Since the model estimation period did not reflect any temperatures lower than 6 degrees, there was no information about the responsiveness of load to low temperature changes for temperatures below 6 degrees. Finally, in addition to the low temperature regression models, Astrapé also used a smoothing adjustment and a proprietary algorithm to produce the load shape in each of the 39 weather years.

ORS's review of the Company's analysis indicates that the approach used was not unreasonable, though we do have some concerns regarding the ability of the model to accurately measure the effect of extreme low temperatures on load and the impact that may have on the estimation of LOLE.

This issue has a significant impact on the level of required winter reserves needed to maintain an LOLE of 0.10. To examine this impact, ORS recalculated the LOLE analysis developed by the Company under two alternative scenarios: one in which 1982 weather is removed, and another in which both 1982 and 1985 weather are removed from the analysis. The purpose of this analysis is to develop an understanding of the importance of extreme cold weather years on the overall LOLE results, not to suggest or recommend that the LOLE analysis exclude these extreme weather years. The weather in 1982 and 1985 reflected very low winter temperatures. The lowest winter temperatures in the 39-year data base occurred in 1985 for DEC.

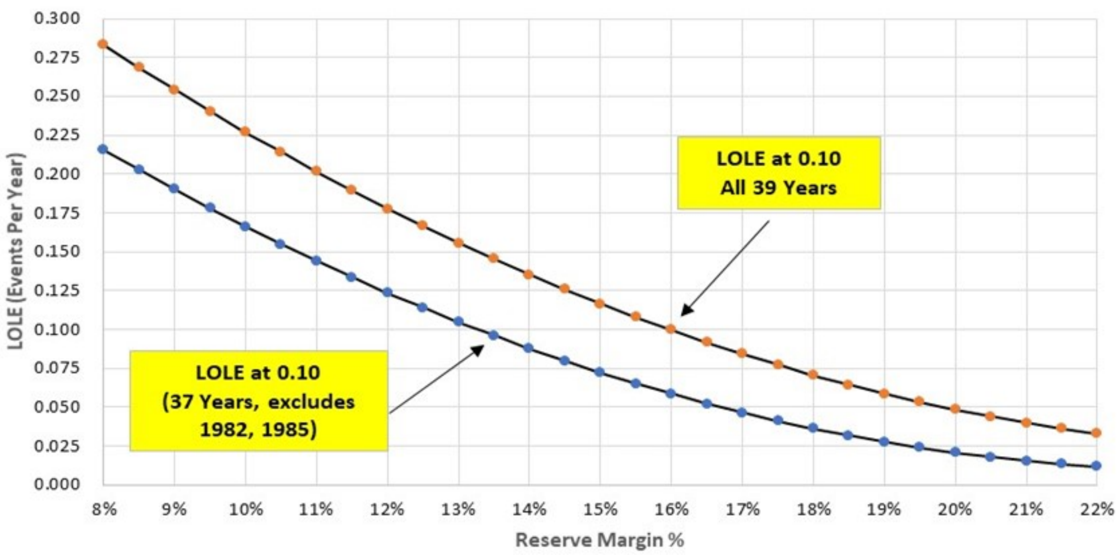
The results of this analysis indicate that the reserve margin required to achieve a 1 day in 10-year LOLE would drop significantly, based on the Company's methodology, if the 1982 and 1985 weather years were excluded from the evaluation. Table 8 below shows the results for DEC.

Table 8
DEC Reserve Margins vs. LOLE
Using Alternative Weather Years

	LOLE - Events Per Year		
Reserve Margin	**All Weather years**	**Weather years excluding 1982**	**Weather years excluding 1982, 1985**
8.0%	0.283	0.263	0.216
8.5%	0.268	0.249	0.203
9.0%	0.254	0.235	0.190
9.5%	0.240	0.222	0.178
10.0%	0.227	0.209	0.166
10.5%	0.214	0.196	0.155
11.0%	0.202	0.184	0.144
11.5%	0.189	0.172	0.134
12.0%	0.178	0.161	0.124
12.5%	0.167	0.150	0.114
13.0%	0.156	0.140	0.105
13.5%	0.145	0.130	0.096
14.0%	0.135	0.121	0.088
14.5%	0.126	0.112	0.080
15.0%	0.117	0.103	0.072
15.5%	0.108	0.095	0.065
16.0%	0.100	0.087	0.058
16.5%	0.092	0.080	0.052
17.0%	0.084	0.073	0.046
17.5%	0.077	0.067	0.041
18.0%	0.071	0.061	0.036
18.5%	0.064	0.056	0.032
19.0%	0.059	0.051	0.028
19.5%	0.053	0.046	0.024
20.0%	0.048	0.042	0.021
20.5%	0.044	0.038	0.018
21.0%	0.040	0.035	0.015
21.5%	0.036	0.032	0.013
22.0%	0.033	0.030	0.012

If 1982 weather alone is excluded, the 0.10 LOLE target is met at a winter reserve margin of 15.0%. If the LOLE analysis excludes both 1982 and 1985 weather, the 0.10 LOLE target is met at a winter reserve margin of 13.5%. Both of these reserve margin targets are significantly below the 16% winter peak reserve margin produced in the Astrapé study for DEC using a full 39-year weather data set. The ORS analysis demonstrates how sensitive the SERVM resource adequacy results are to just a couple of years of extreme low temperatures out of the full 39-year period. While ORS did not attempt to calculate the effect on the combined DEP/DEC reserve margin using only 37 years of weather data, it is likely that a similar reduction in the required winter peak reserves would be produced. Figure 3 provides a comparison of the LOLE curves based on the full 39 years of weather (1980 – 2018) and 37 years of weather (excluding weather for the years 1982 and 1985).

Figure 3
DEC Reserve Margin vs. LOLE
39 Years of Weather vs 37 Years of Weather
(excluding 1982, 1985 Weather Years)



ORS also reviewed other inputs in the LOLE analysis, including the neighboring utility tie-line support that is assumed to be available during emergencies. The SERVM analysis assumed emergency support from seven interconnected utilities and regions, not including support from DEP. The analysis developed 39-year load-weather relationships for each of these neighboring utilities so that the SERVM Monte Carlo analysis would measure the load diversity of these external sources under varying weather conditions. This is an attempt to reflect that fact that weather patterns tend to be regional. For example, during extreme cold weather on the DEC system or on the combined DEP/DEC system (which is actually used to set the reserve margin in this 2020 IRP), other neighboring utility systems may also experience extreme cold weather, limiting the availability of otherwise available emergency imports. The model attempts to portray such dependencies. The is a significant modeling enhancement, which would appear to increase the ability of the analysis to reflect likely events during extreme low temperatures.

ORS also examined the assumed probability distribution of load forecast errors ("LFE"). Normally, in these types of economic analyses, the probability distribution associated with load forecast errors is assumed to be symmetric – in other words, equal probabilities of an over-forecast and an under-forecast. In this case, pursuant to the Stakeholder process, the Company employed a non-symmetric probability distribution such that the likelihood of an over-forecast is greater than an under-forecast. Table 9 shows this load forecast probability distribution based on a four-year ahead forecast.

Table 9
SERVM Load Forecast Error

Assumed Forecast % Error*	Probability
95.80%	10%
97.30%	25%
100.00%	40%
102.00%	15%
103.10%	10%

* A % less than 100% has the effect of reducing the peak load forecast.

The load forecast error distribution is used in the Monte Carlo analysis to either reduce or increase the load forecast for each weather year. For example, based on the distribution, 10% of the time, the computed load forecast is assumed to be too low and would be increased by applying a factor of 103.10% to each load value. All else being equal, this has the effect of increasing the loss of load events in that scenario. While conceptually, the inclusion of LFE in an LOLE analysis is reasonable, the estimation of an LFE probability distribution is a potentially contentious issue. The Astrapé analysis derived the four-year ahead forecast errors from recent experience in economic forecast errors contained in the Congressional Budget Office forecast of Gross Domestic Product ("GDP"). While a GDP forecast error might be one of the components of a load forecast error for a utility it is not the only source of errors. Putting aside weather-related errors, which are separately reflected in the Company's LOLE analysis, there are additional sources of forecast errors beyond GDP or other measure of economic activity. Among these are the forecast modeling errors themselves. That is, the error in a forecast model predicting load, given know input factors such as weather and economic activity. This model related error has a probability distribution. As such, the usefulness of reflecting LFE in the resource adequacy analysis is questionable. Ironically, because the LFE probability distribution is weighted towards an assumed over-forecast, the inclusion of LFE in the Company's analysis actually resulted in a lower reserve margin, all else being equal.[41] However, using a symmetric LFE probability distribution in the analysis increased the reserve margin by 1% (16% to 17%).

The final resource adequacy issue that ORS reviewed was associated with other work that Astrapé performed that concerned the capacity value assumptions for standalone solar and solar plus battery storage resources. Astrapé derived capacity value assumptions based on similar modeling techniques using its SERVM model. These capacity values represent the percentage of installed nameplate capacity that contributes to meeting peak loads in the summer and winter. Since the winter peak drives the need for capacity on both the DEP and DEC systems, the winter capacity values of solar and solar plus battery are of the main importance.

The Company used a 1% winter capacity value for standalone solar and a winter capacity value of 25% for solar plus battery, based on an assumed 4-hour discharge assumption. These capacity values, which materially impact the economic value of solar, are based on two Astrapé analyses of the effective load carrying capacity ("ELCC") of various solar and solar plus battery technologies.[42] ORS has evaluated these two studies and has found them to be generally reasonable. They are both based on simulations using the SERVM model that is used to determine the Company's planning reserve margins. ORS is concerned that the IRP report (including appendices) did not discuss how the actual inputs into the Company's resource expansion plan modeling (the System Optimizer model) were derived from the capacity value summary results reported. For example, the standalone solar capacity values presented in the 2018 Astrapé ELCC study as part of the Company's avoided cost case (Docket No. 2019-185-E) were reported for various levels of solar capacity ("0", "existing plus transition", and 4 additional tranches comprised of either fixed or tilt solar technology), while for IRP planning purposes, a single 1% capacity value assumption was used for all assumed levels of solar capacity on the system. Given the potential significance of the assumed solar capacity values, ORS recommends the Company provide an explanation of the derivation of the actual planning model inputs.

Further discussion of the solar and solar plus battery capacity value results is included below in the Generic Resources section of this report.

[41] Astrape reported a sensitivity analysis wherein the LFE was removed. The resulting reserve margin required to meet a 0.10 LOLE increased in this "LFE removed" scenario.

[42] The solar capacity values are developed in a 2018 Astrape report ("Duke Energy Carolinas and Duke Energy Progress Solar Capacity Value Study") and a 2020 Astrape report that is included as an attachment to the IRP Report ("Attachment IV Duke Energy Carolinas and Duke Energy Progress Storage Effective Load Carrying Capability (ELCC) Study").

Conclusions – Resource Adequacy – Reserve Margin Issues

Overall, ORS concludes that the Company's 17% winter peak reserve margin analysis meets the requirements of Act 62, is reasonable and represents a high level of methodological sophistication. The methodology used by the Company to develop its analysis, which uses the SERVM model to perform a Monte Carlo analysis that incorporates probability-based risk profiles for numerous factors that affect resource adequacy is also reasonable. A 17% winter peak reserve margin is generally consistent with the target winter peak reserve margins of a number of utilities in the Mid-Atlantic and Southeast areas. Table 10 below shows a compares the DEP/DEC winter peak reserve margin to those of a number of these utilities.

Table 10
Comparison of Utility Winter Peak Reserve Margins

Utility	Winter Peak Reserve Margin
DEP/DEC	17%
Dominion Energy South Carolina	21%
Southern Company	26%
TVA	25%
Louisville Gas and Electric/ Kentucky Utilities	17% to 25%
Florida Power and Light Co.	20%

Recommendations – Resource Adequacy – Reserve Margin Issues

2. ORS recommends the Company provide a more detailed discussion of the specific methodology used to develop the synthetic loads for extreme low temperature periods. While the Resource Adequacy Report provides an overview of this issue, it does not provide sufficient detail regarding how the analysis was conducted or what specific additional adjustments were made to the load data at extreme low temperatures. This detail was provided in response to discovery in this proceeding, however, we recommend this level of detail be included in future IRPs as part of a comprehensive technical appendix. **(L)**

3. ORS recommends the Company further develop its methodology to model the effects of extreme low temperatures on winter peak load. Given the significance of this issue, as discussed in the ORS Report, there may be alternative methodologies that the Company could consider to develop its synthetic loads in hours in which the temperatures fall significantly below the temperatures experienced during the

weather/load estimation period (i.e., neural net model training period). We recommend this be addressed in future IRPs through the Company's stakeholder process. **(L)**

4. ORS recommends the Company provide a detailed discussion in the IRP Report or appendices that explains how the results of the Astrapé 2018 Solar Capacity Value Study were used to derive the assumed winter peak standalone solar capacity value of 1%. We recommend this information be included in a modified IRP in this proceeding. **(N)**

Energy Efficiency and Demand Side Management

The Company's IRP includes both EE and DSM (DR) programs in its IRP analyses. Currently, the Company has 12 EE and 5 DSM offerings in the DEC territory that were available as of December 31, 2019.[43]

Specifically, the programs offered were:

Residential EE

- EE Appliances and Devices
- EE Education
- Multifamily EE
- My home energy report
- Income-Qualified EE and Weatherization Assistance
- Energy Assessments
- Smart Saver EE

Non-Residential EE:

- Non-Residential Smart $aver Prescriptive
- Non-Residential Smart $aver Custom
- Non-Residential Smart $aver Custom Assessment
- Non-Residential Smart $aver Performance Incentive
- Small Business Energy $aver

Residential DSM:

- Power Manager

Non-Residential DSM:

- PowerShare

[43] DEC 2020 IRP pg. 246, DEP IRP, pg. 237.

- Interruptible Service (IS)
- Standby Generator (SG)
- EnergyWise Business

For the IRP, the Company's base case energy savings projection was based partly on DEC's five year EE program plan for 2020-2024, and partly on results that were determined in an EE market potential study ("MPS") that was performed by Nexant, Inc. ("Nexant") and that was completed in June 2020. The Company asserted that Nexant's results were suitable for use as a long range projection, however, the study did not "attempt to closely forecast short-term EE achievements from year to year."[44] Therefore, the Company developed the EE/DSM saving projections for the IRP by blending DEC's five-year program planning forecast into the long-term achievable potential projections from the market potential study.

Nexant's MPS study determined feasible (technical, economic and realistic achievable market potential) energy savings for EE programs over short term (5-year projection), medium term (10-year projection), and long term (25-year projection) periods. Nexant relied on its TEAPot (Technical, Economic, and Achievable Potential) model to calculate potential energy savings based on input assumptions that included sales/load forecasts that were disaggregated into customer-class and end use components, electricity prices, discount rates, historic program energy savings, fuel shares, current market saturation, and program costs. Nexant examined a range of commercially available EE measures by end-use.[45]

Nexant derived estimates of cumulative technical potential, which ignored program costs and focused strictly on energy savings, assuming that the energy savings would be technically feasible. Nexant determined that the upper limit for technical potential as a percentage of 2044 electricity sales would be approximately 32% in the DEC territory. Nexant evaluated the economic potential of EE programs using the Total Resource Cost ("TRC") test and found that all existing EE programs would continue to be economic based on the TRC test. Nexant also evaluated the achievable potential of EE programs based on the willingness of customers to participate and determined achievable energy savings would likely average approximately 0.82% of annual Base Sales in the DEC territory over the 25-year study period.[46]

[44] DEC 2020 IRP, pg. 35.
[45] DEC 2020 IRP Attachment V, Nexant Duke Energy EE and DSM MPS, pg. 1.
[46] *Id*. pg. 2

Nexant developed projections of EE impacts over the 25-year study period for three energy savings scenarios, as follows:

- Base Scenario – consistent with existing EE program portfolio.
- Enhanced Scenario – Base Scenario plus increased program spending (via incentives) to attract an increased level of EE customer participation.
- Avoided Energy Cost Scenario – Base Scenario plus uses higher avoided energy costs resulting in higher valued EE programs. Potentially includes additional cost-effective measures and increased achievable potential.

The Company then blended Nexant's scenarios with its 5-year EE program plan for 2020-2024 to develop Base, High and Low EE scenarios that were used in the IRP, pursuant to Act 62 requirements. The Company developed the following three (3) forecasts:

- Base Case forecast – blends together DEC's five (5) year plan with Nexant's Base Achievable Portfolio. Residential savings average 1.29% of sales[47] in the 2021-2035 period.
- High Case forecast – incorporates impacts of both Nexant's Enhanced and Avoided Cost Sensitivity Scenarios. Yearly energy savings are between 0% and 11% higher than the Base Case for the 2021-2035 period.[48]
- Low Case forecast – impacts are assumed to be 75% of the Base Case.

The Base Case forecast was derived by using the Company's five (5) year plan for the 2020-2024 period, then by blending five (5) year plan and the MPS for the 2025-2029 period, and then finally using the MPS for the 2030-2035 period.

The company indicates that future DSM efforts will be focused on reducing winter peak demand. This appears to be a reasonable decision as the majority of current DSM efforts are focused on summer peak reduction.

ACEEE conducts yearly evaluations of statewide EE efforts, and ranks states against each other on a variety of metrics. The percentage reduction in retail energy sales is one such metric. Though the ACEEE State Energy Efficiency Scorecard compares statewide efforts, it is a useful benchmark for comparing program success across the country. The

[47] NCPS DR 2-17.
[48] DEP 2020 IRP, p. 261-263; DEC 2020 IRP p. 269-71.

Company's projected 1.29% of sales savings would be given a score of 4.5 of a possible 7 in ACEEE's 2019 report, scoring in the top quartile, which is a reasonably high ranking.[49]

The Commission approved the Company's most recent five-year DSM and EE Program plan in its order on January 15, 2021, which has a goal of achieving energy savings of 1% of annual retail sales.[50] Per the IRP forecast, the Company is poised to exceed its 1% of retail energy sales savings goal.

The Company's EE sensitivity analysis indicated that the high EE case would be even more economic than the base case, but by just a small amount, 0.4%.[51] The Company believes "executability risks" of being able to achieve the high level of EE savings outweigh the potential savings, and therefore it did not include the High EE case as part of its Base Case plan.[52]

ORS notes that the Company did not explain its concern with executability risks, and also it did not fully evaluate fuel cost risk in its EE sensitivity evaluation. In that sensitivity case, the Company strictly compared a case with its base assumptions (including base fuel cost assumptions) to a base case that incorporated the high EE forecast assumptions. However, the Company did not assess the impact of the high or low EE forecasts under different fuel and CO_2 cost assumptions. ORS recommends the Company provide additional EE cases examining different levels of fuel and CO_2 prices, both high and low.

Finally, the Low DSM/EE case is assumed to be 75% of the base case. It is not clear how this scale factor was chosen. ORS recommends that the Company provide additional detail regarding this figure and explain why the Company believes it represents a reasonable lower band estimate.

<u>Recommendations – Energy Efficiency and Demand Side Management</u>

5. ORS recommends the Company provide additional justification for selecting the Base EE/DSM case as opposed to the High EE/DSM case for use in Portfolio A, given that the High EE/DSM case may provide greater customer benefits. We recommend this information be included in a modified IRP in this proceeding. **(N)**

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[49] https://www.aceee.org/sites/default/files/publications/researchreports/u1908.pdf, p.39.
[50] *Application of Duke Energy Carolinas, LLC for Approval of New Cost Recovery Mechanism and Portfolio of Demand-Side Management and Energy Efficiency Programs*, Docket 2013-298-E, Order Issued January 15, 2021 (Order No. 2021-32).
[51] DEC 2020 IRP pg. 169. Table A-9. See "High EE" row.
[52] DEC 2020 IRP p. 171.

6. ORS recommends that in addition to the sensitivity cases included in Table A-9, the Company also evaluate high and low levels of EE/DSM using high fuel/CO2 and low fuel/CO2 assumptions. We recommend this information be included in a modified IRP in this proceeding. **(N)**

7. The Company provided no basis for the low EE/DSM forecast that it used in the IRP. The Company's approach may be reasonable; however, it would be a better practice to provide more justification as to how it derived the low EE/DSM forecast. ORS recommends the Company provide additional justification or consider other approaches for deriving the low EE/DSM forecast. We recommend this be addressed in future IRPs through the Company's stakeholder process. **(L)**

Natural Gas Price Forecasts

The Company developed three natural gas price forecasts, including a low, base, and high forecast. The Company developed these forecasts using a method that blended together a market-based forecast with a fundamentals-based forecast. The company used market-based pricing for its 2021-2030 forecasts, and it gradually transitioned that to a 100% fundamental based forecast by 2035 and beyond.[53]

The market-based forecast came from a [redacted] which the Company used as its market assumptions for 2020-2030. Beginning in 2031, [redacted] which was referred to as the North American Natural Gas Long-Term Outlook, February 2020. By 2035, the forecast was completely based on the [redacted] fundamentals forecast.[54]

To derive high and low forecasts, the Company determined the implied volatility within the gas strip and used that to project 90th and 10th percentile estimates, which it used as its high and low market-based forecasts. [redacted][55]

[53] DEC 2020 IRP pg. 157.
[54] ORS DR 2-3a.
[55] *Id.*

The following three graphs compare the Company's low, base and high gas price forecasts to other recent utility and industry forecasts that are publicly available and have been released since December 2019. ORS has computed "consensus forecasts" by averaging the publicly available forecasts each year, including DEC's natural gas price forecasts. The other utility forecasts were from relatively recent IRPs, including Kentucky Power,[56] Xcel Upper Midwest,[57] DESC,[58] Virginia Power,[59] DTE Electric,[60] Avista,[61] and Tucson Electric.[62] In addition, EIA[63] forecasts were also included, with EIA's High Oil and Gas Supply forecast included in the low consensus forecast, EIA's Reference Case in the base consensus forecast, and EIA's Low Oil and Gas Supply in the high consensus forecast.

[56] Kentucky Power 2019 Integrated Resource Planning Report, p. 78. https://psc.ky.gov/pscecf/2019-00443/sebishop%40aep.com/12202019120748/KPCO_2019_IRP_Volume_A_Public_Version.pdf
[57] Excel Energy 2019 Upper Midwest Intergrated Resource Plan; Figure 2-10. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7BF0AB0573-0000-C11C-B7B2-2FA960B89BD1%7D&documentTitle=20206-164371-01
[58] DESC 2020 IRP, Docket No. 2019-226-E, ORS AIR 2-3. .
[59] Virginia Power 2020 IRP; Appendix 4O; page 4. https://www.dominionenergy.com/-/media/pdfs/global/2020-va-integrated-resource-plan.pdf?la=en&rev=fca793dd8eae4ebea4ee42f5642c9509
[60] DTE Electric Company 2019 IRP; Appendix S; Exhibit 11. https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000006YILTAA0
[61] Natural Gas IRP; TAC 4: Wesnesday November 18,2020; p.87. https://www.myavista.com/about-us/integrated-resource-planning
[62] Tucson Electric Power Company; 2020 Integrated Resource Plan; Chart 32. https://www.tep.com/wp-content/uploads/TEP-2020-Integrated-Resource-Plan-Lo-Res.pdf
[63] Annual Energy Outlook 2020; Table 13. Natural Gas Supply, Disposition, and Prices. https://www.eia.gov/outlooks/aeo/data/browser/#/?id=13-AEO2020&region=0-0&cases=ref2020~highogs~lowogs&start=2018&end=2050&f=A&linechart=~~~~~~~~~ref2020-d112119a.60-13-AEO2020~highogs-d112619a.60-13-AEO2020~lowogs-d112619a.60-13-AEO2020&map=&ctype=linechart&sourcekey=0

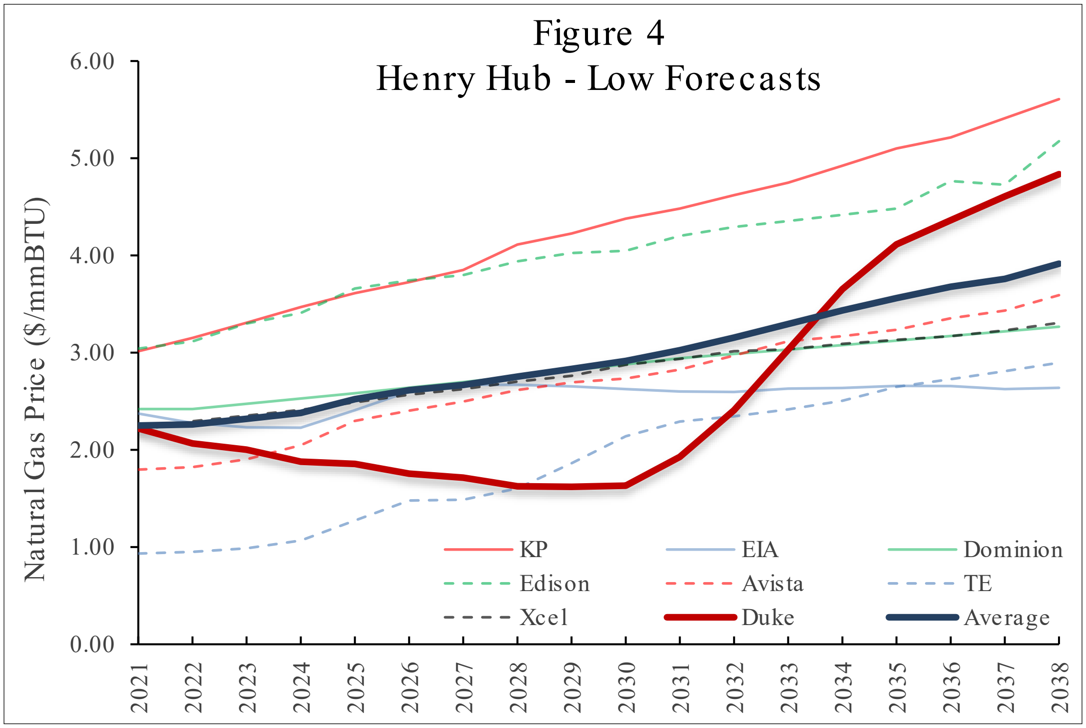
Figure 4
Henry Hub - Low Forecasts
Natural Gas Price ($/mmBTU)
6.00
5.00
4.00
3.00
2.00
1.00
0.00
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
KP
EIA
Dominion
Edison
Avista
TE
Xcel
Duke
Average

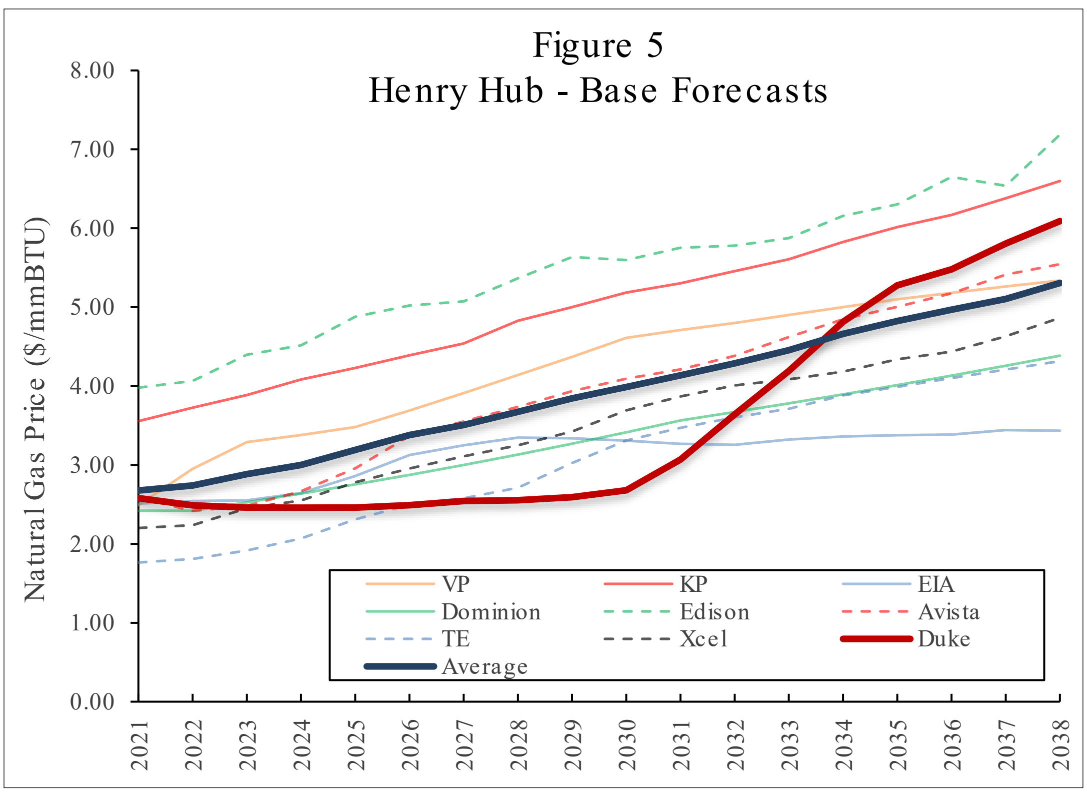
Figure 5
Henry Hub - Base Forecasts
Natural Gas Price ($/mmBTU)
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
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2037
2038
VP
KP
EIA
Dominion
Edison
Avista
TE
Xcel
Duke
Average

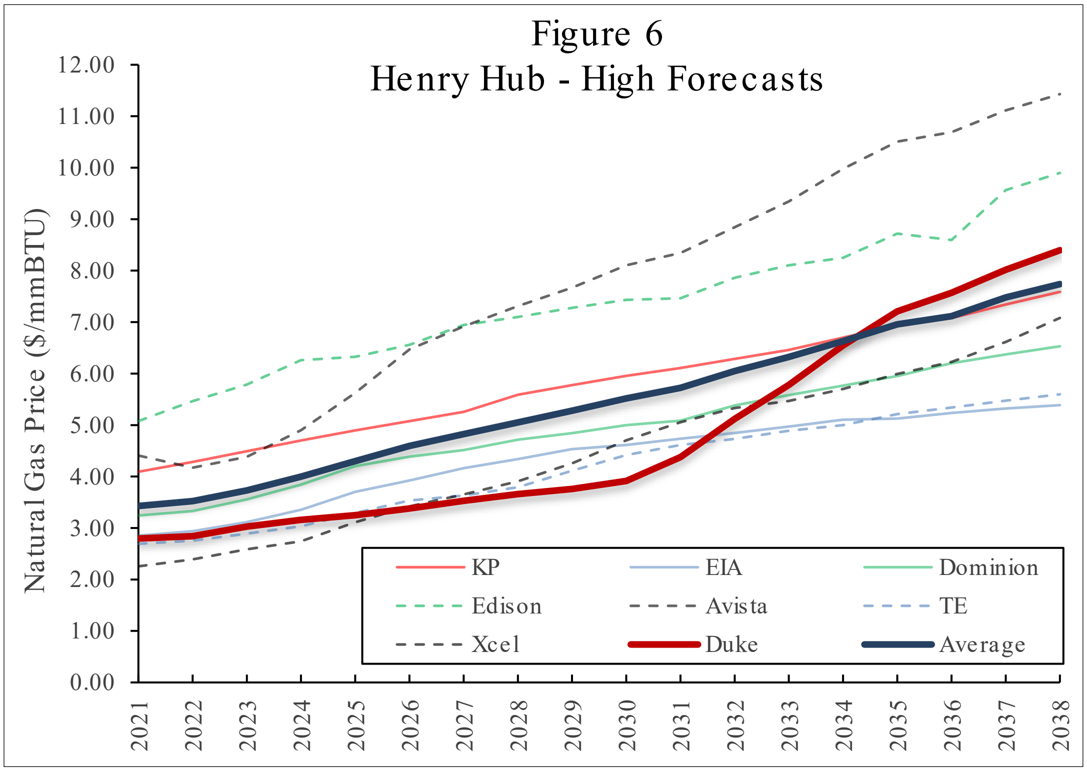
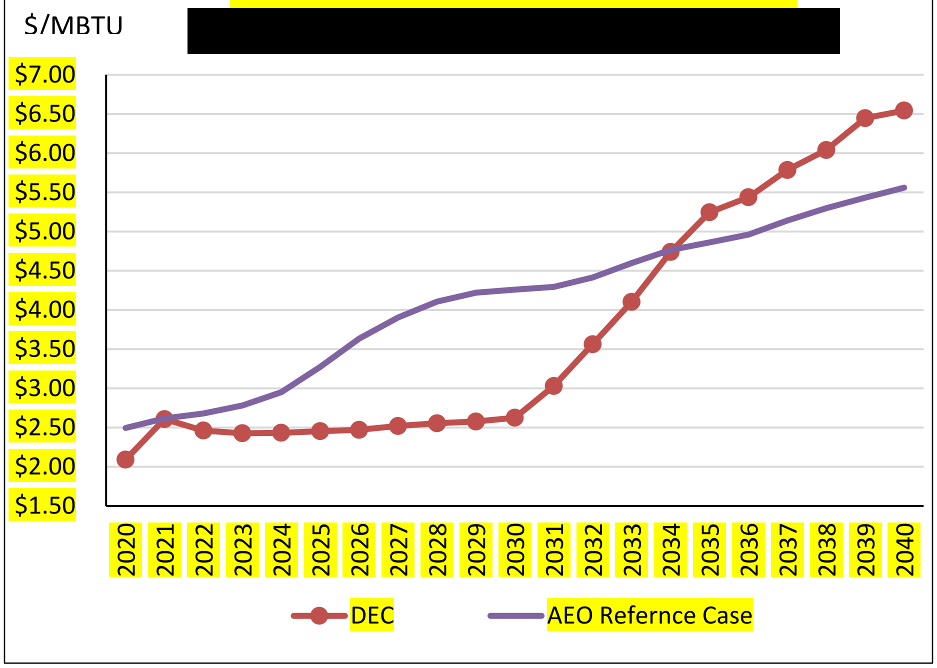


Figure 6
Henry Hub - High Forecasts

The Company's gas price forecasts are consistently lower than the consensus forecasts in all three (3) cases by a small amount over the period of 2021 to about 2035. After that the DEC forecast actually exceeds the consensus forecast by a small amount in all three (3) cases. ORS recognizes that the future is unknown and that natural gas price forecasts have been lowered considerably over the last ten years. While DEC's forecasts do appear to be a little low over the planning horizon, the important question is whether DEC's forecasts are outliers when compared to the other forecasts, and the answer is no. Some of the other comparable forecasts are actually lower or are close to DEC's forecast over the planning horizon.

While DEC's forecasts do not appear to be unreasonable, there may be an opportunity for improvement. The development of the Company's base gas price forecast is illustrated in the following graph, which shows that the DEC Base forecast is equivalent to the market forecast (NYMEX) until 2030, then trends into the fundamental forecast ([redacted]) until 2035, and follows the fundamental forecast thereafter.

Figure 7
DEC Base Blended Gas Price Forecast



There are a few noticeable issues regarding the Company's forecast including the fact that it is rather flat for about ten years. The Company appears confident that based on actual market quotes it can lock in its gas supply for its entire system for the next ten years, which in our experience would be unusual for an electric utility to do. Second, even the Company's own fuel forecast vendor and EIA appear to have a different view of how natural gas prices will increase over time, and those two forecasts are largely consistent.

We point these concerns out because low gas price forecasts could result in indicating that natural gas-fired resources are comparatively less expensive than they otherwise would be relative to other resource alternatives. As an example, assuming a combined cycle unit has a 6.5 MBTU/MWh average heat rate, the dispatch price of that unit in 2030, when comparing the Company's gas price forecast estimate to the EIA AEO estimate, would be $17.06/MWh versus $27.68/MWh, respectively, which amounts to over a 60% difference in dispatch price, which certainly would favor gas-fired resources.

The Company discusses its gas supply outlook in detail in Appendix F,[64] in which it notes that a decline in the production of natural gas occurred over the course of 2020 and it is expected to continue into 2021 partly due to the economic slowdown caused by COVID-

[64] DEC 2020 IRP pg. 307.

19. This is consistent with the Company's low price forecast over the short-term, but it does not necessarily mean that prices will continue to remain flat for the next ten years. The Company discusses that 5 and 10-year observable market curves are at $2.39 and $2.53, which is consistent with the Company's base forecast, however, as discussed above, it is not clear that the Company would or even could in fact lock in its entire gas supply for the next ten years.

In Appendix F, the Company also discusses its need for "additional upstream firm interstate transportation service to support existing and future natural gas generation."[65] With the cancellation of the Atlantic Coast Pipeline ("ACP") in July 2020, the Company has no active projects to expand its interstate gas supply. Without the ACP, the Company notes it will not have any direct access to Marcellus and Utica shale basins of West Virginia, Pennsylvania, and Ohio natural gas supply. The Company also noted that it will still need additional upstream firm interstate transportation service to support existing and future gas generation despite the cancellation of the ACP. For purposes of the IRP, the Company assumes that incremental firm transportation service would be obtained but from other suppliers than the ACP, and associated pipeline costs were modeled in the IRP. For example, the Company assumed that for each new CCGT modeled, firm inter- and intra-state transportation service would cost $114 million per year. The Company assumed that non-firm service (just intrastate) would be needed for new CTs at a cost of $4 million per year.[66]

<u>**Recommendations - Natural Gas Price Forecasts**</u>

8. ORS recommends the Company review its natural gas price forecasting methodology and investigate alternative approaches. We recommend this be addressed in future IRPs through the Company's stakeholder process. **(L)**

CO_2 and Other Environmental Issues

In Chapter 16 entitled, Sustaining the Trajectory to Reach Net-Zero, the Company discusses its corporate sustainability goals, which it states were set in 2019 calling for a reduction in CO_2 emissions by at least 50% from 2005 levels by 2030, and to achieve net-zero CO_2 emissions by 2050. The Company notes that DEC and DEP have already made considerable progress as they have reduced emissions by 38%, which exceeds the industry average of 33%.

The Company explains that the path forward to being able to meet its carbon objectives will require actions that it as well as others will have to take, including:

[65] *Id.* pg. 310.
[66] NCPS DR 3-26.

- Investing in the grid to allow growth in renewables and energy storage and to implement intelligent grid controls,
- Developing proper planning tools to study dynamic impacts to leverage energy storage and customer programs such as rooftop solar and EV charging,
- Continuing to implement EE and DSM,
- Relying on natural gas as a bridge to renewables,
- Advancing clean technologies such as small modular nuclear reactors,
- Continuing to operate its nuclear fleet, which will require license renewals, and,
- Establishing supportive policies that would lead to CO_2 reductions.

As mentioned, the Company believes that natural gas will play an important role in helping to reduce emissions over time and maintain affordable costs, as it states:

> In adding roughly equivalent amounts of natural gas combined cycle and solar generation, the ability of natural gas combined cycle generation to displace the coal generation at much higher capacity factors drove the significantly larger portion of the 38% carbon reduction while keeping customer costs low. Finding the right balance between accelerating the pace of emissions reductions and new technology deployment while maintaining affordability for customers will continue to be an important consideration moving forward.[67]

To address stakeholder concerns about the potential impact that adding natural gas units could have on customer costs if those assets are ultimately retired early, the Company performed a sensitivity analysis in which it modeled natural gas resources (CTs and CCGTs) with a shortened operating life of 25 years. The Company found that the optimization model still selected natural gas units economically.[68]

With regard to the bulleted item above concerning the need for supportive policies, the Company asserts that unless federal and or state CO_2 policies are implemented, the Company's CO_2 emissions would not likely exceed a 55% reduction and could actually

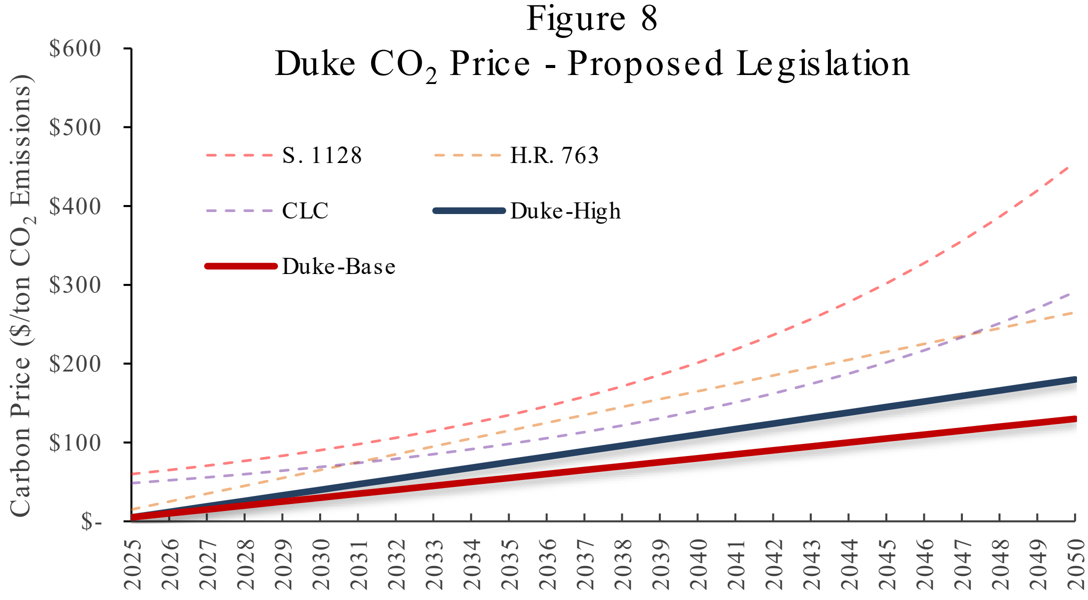
[67] DEC 2020 IRP, pg. 136.
[68] *Id.*

begin to increase once again, as demonstrated by results determined in the Company's Base Case without CO_2 portfolio.[69]

The Company also notes that supportive policies will be required to accelerate research, development and deployment of advanced technologies, to address interconnection issues, including interconnection queue reform, interconnection related transmission and distribution upgrades, transmission right-of-way acquisition, permitting, regulatory approval processes, and others.

In light of the above discussion, it is reasonable that although no federal or state CO_2 policies have been implemented to date, the Company has modeled CO_2 price sensitivity cases in the IRP, including a base CO_2 case of $5/ton beginning in 2025 that grows by $5/ton per year, a high CO_2 case of $5/ton beginning in 2025 that grows by $7/ton per year. In addition to those, the Company also evaluated $0/ton CO_2 cases as well. ORS examined the reasonableness of the Company's CO_2 assumptions by comparing them to other CO_2 forecasts that are publicly available such as from recently proposed legislation, EIA, and other utilities. The graphs below illustrate how the Company's forecasts compare, when compared to legislative proposals, EIA, and other utilities.

Figure 8
Duke CO_2 Price - Proposed Legislation



A brief description of the proposals in the graph are:

- The Climate Leadership Council states that it attempts to develop consensus climate solutions in a bipartisan way. The Council's plan, as depicted above, starts at

[69] DEC 2020 IRP, pg. 17.

$40/Ton (2017$) and increases at 5% above inflation each year. Its goal is to reduce CO_2 by 50% from 2005 levels by 2035.[70]

- The Energy Innovation and Carbon Dividend Act ("H.R. 763") was introduced in the U.S. House of Representatives on January 24, 2019 as another bipartisan attempt to address carbon emission issues.[71] This proposal starts at $15/Ton and increases at $10/Ton per year ($15/Ton if targets are not met), and the fee stops increasing if emissions decline by 90% compared to 2016 levels. The objective of the bill was to reduce emissions by approximately 40% by about 2030.

- The American Opportunity Carbon Free Act of 2019 (S. 1128)[72] was introduced into the senate by two Senators on January 24, 2019. The legislation would impose a tax starting at $52/Ton and would rise at 6% above inflation each year. By 2035, the emissions are projected to be about 50% below the 2005 emission level.

- Duke Energy's 2020 Base Case forecast begins at $5/Ton in 2025 and escalates at $5/Ton each year.

- Duke Energy's 2020 High CO_2 price forecast begins at $5/Ton in 2025 and escalates at $7/Ton each year.

From the Figure above, the Company's two proposals track reasonably well with the other proposals until around 2030 to 2035, though they are still lower than the legislative proposals during that period. To date, none of the legislative proposals have gotten much traction; however, that could conceivably change under the Biden administration with the new composition of Congress.

The following figure compares Duke Energy's forecasts to EIA projections and shows that Duke Energy's forecasts are reasonably consistent with EIA's.[73]

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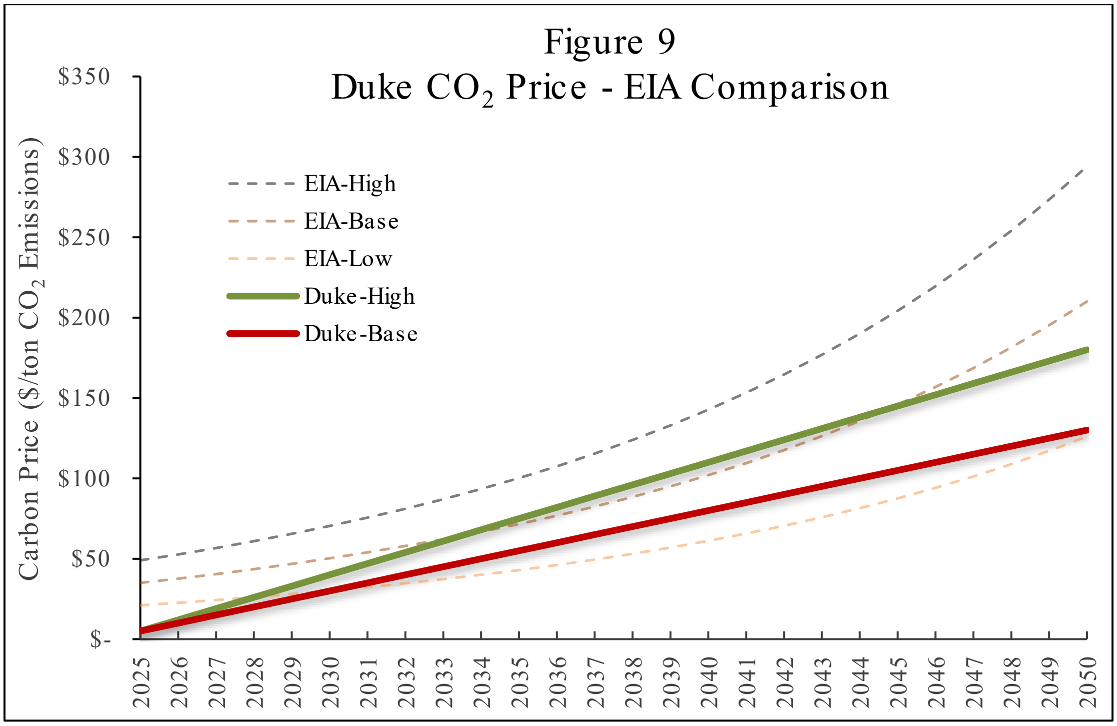
[70] https://clcouncil.org/Bipartisan-Climate-Roadmap.pdf.https://clcouncil.org/Bipartisan-Climate-Roadmap.pdf. Baker and Shultz are James Baker and George Shultz, both former republican Secretaries of State.

[71] https://www.congress.gov/bill/116th-congress/house-bill/763/text https://www.congress.gov/bill/116th-congress/house-bill/763/text

[72] https://www.congress.gov/bill/116th-congress/senate-bill/1128/text https://www.congress.gov/bill/116th-congress/senate-bill/1128/text

[73] EIA Altenative Policies March 2020, p 16. https://www.eia.gov/outlooks/aeo/pdf/AEO2020_IIF_Alternative_Policies_FullReport.pdf



The following figure compares Duke Energy's Base CO_2 forecast to other publicly available base CO_2 utility forecasts and shows that Duke Energy's forecasts are also reasonably consistent with those forecasts, though in fact, Duke Energy's forecast is higher than the average of the forecasts. The other utility forecasts include PacifiCorp,[74] DESC,[75] Xcel Energy,[76] DTE Electric,[77] Virginia Power,[78] and Kentucky Power,[79] and the average of each forecast (including Duke Energy's).

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[74] Pacificorp 2019 IRP; Chapter 7 – Figure 7.3 CO2 Prices, https://pscdocs.utah.gov/electric/19docs/1903502/310626Chapter7Figure7.3CO2Prices10-25-2019.xlsx

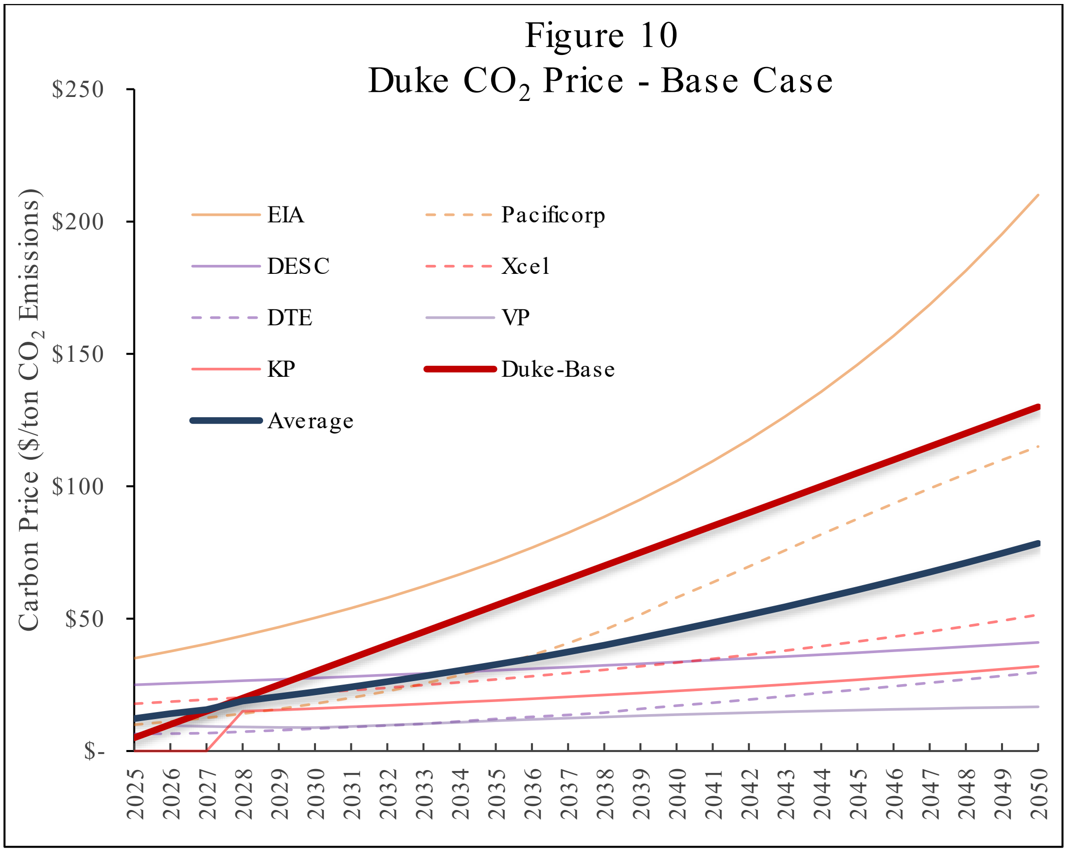
[75] DESC 2020 IRP, pg.44.

[76] Appendix F2: Strategist Modeling Assumptions & Inputs, pg. 3; Xcel Energy 2020-2034 Upper Midwest Resource Plan. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={00FBAE6B-0000-C414-89F0-2FD05A36F568}&documentTitle=20197-154051-01

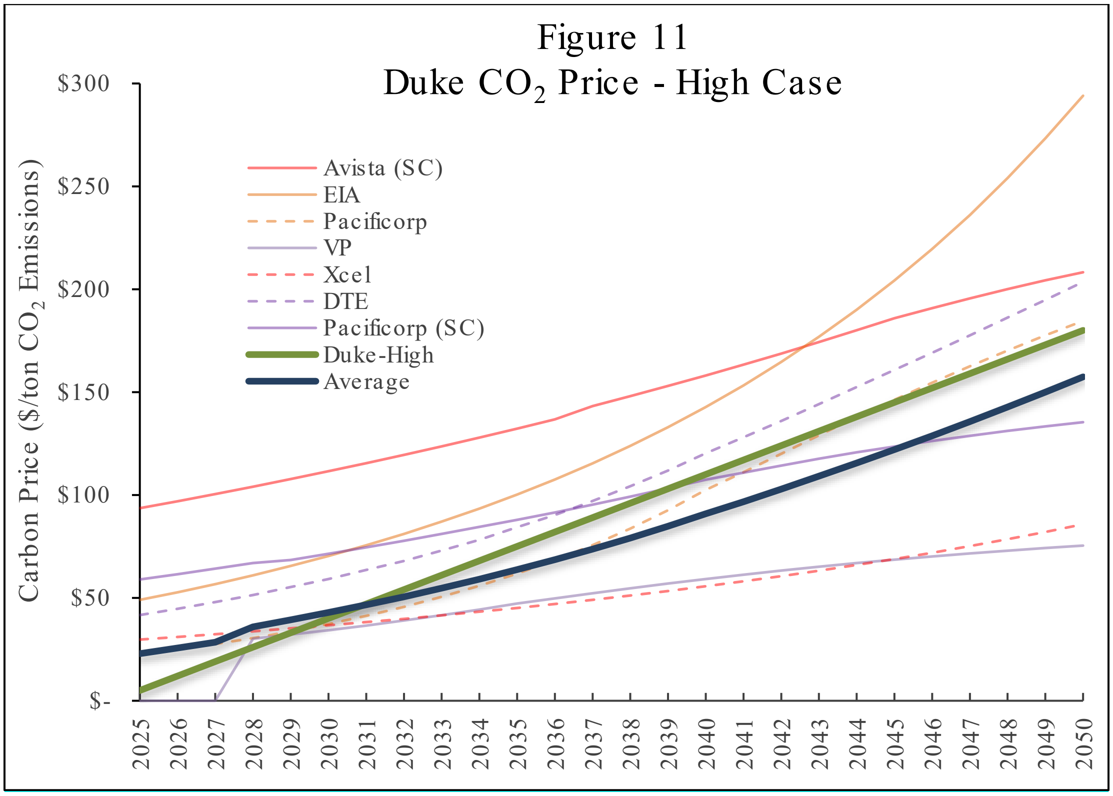
[77] DTE Electric Company 2019 IRP, Introduction, Figure 4.4.2, p. 26. https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000006YlLTAA0

[78] ICF Commodity Forecast: CO2, Appendix 4O, Virginia Electric and Power Company's 2020 Integrated Resource Plan. https://www.dominionenergy.com/-/media/pdfs/global/2020-va-integrated-resource-plan.pdf?la=en&rev=fca793dd8eae4ebea4ee42f5642c9509

[79] Kentucky Power 2019 Integrated Resource Planning Report, Significant Changes from 2016 IRP, pg. 5; https://psc.ky.gov/pscecf/2019-00443/sebishop%40aep.com/12202019120748/KPCO_2019_IRP_Volume_A_Public_Version.pdf



Lastly, the following figure compares Duke Energy's High CO_2 forecast to the other publicly available high CO_2 utility forecasts and shows that Duke Energy's forecast is once again reasonably consistent with the other forecasts, though in fact, Duke Energy's forecast is higher than the average of the forecasts.



Other Environmental Issues

In addition to planning for meeting its own corporate carbon reduction goals, there are a number of environmental regulations at the Federal and State level that the Company is required to meet. DEC discusses each regulation in Appendix I of the IRP, entitled Environmental Compliance. The regulations include:

Air Quality

- Acid Rain Program – Resulted in significant reductions in SO_2 and NO_x since about 2000. In compliance.
- Cross-State Air Pollution Rule ("CSAPR") – Must meet state emission limits for SO2 and NOx on an annual basis. In Compliance.
- Mercury and Air Toxics Standards ("MATS") – Requires emission limits for hazardous air pollutants ("HAP"). Fully In compliance.
- 2002 North Carolina Clean Smokestacks Act ("NC CSA").
- 8-Hour Ozone National Ambient Air Quality Standards ("NAAQS") – Fully in attainment.
- SO_2 NAAQS – Fully in attainment.

- Fine Particulate Matter ($PM_{2.5}$) NAAQS – Fully in attainment.
- Greenhouse Gas New Source Performance Standards ("NSPS") – EPA established CO_2 limits for new coal and CCGT units built after 2014. These limits have no effect on DEC as its new CCGT units meet the requirements, and it is not proposing any new coal units.
- CO_2 Regulations Existing Coal and Natural Gas Units – Clean Power Plan ("CPP") rule finalized, then repealed. Affordable Clean Energy ("ACE") Rule created as replacement, however, now vacated, and new EPA rulemaking to take place.

<u>Water Quality and By-Products</u>

- Cooling Water Act 316(B) Cooling Water Intake Structures – Fish Impingement and entrainment. DEC expects the state to determine necessary entrainment controls for affected units in the 2020 – 2023 time period and intake modifications, if necessary, in the 2022 – 2026 time period.
- Steam Electric Effluent Limitation Guidelines ("ELG") – Prohibits discharge of bottom and fly ash transport water, flue gas mercury control wastewater, and establishes limits on discharge of wastewater from Flue Gas Desulfurization ("FGD") systems, and leachate from coal combustion residual landfills and impoundments. The only DEC unit requiring emissions upgrades currently is Cliffside Unit 5, which is in the process of installing a wastewater treatment system that should be completed by the 4th Quarter of 2021. In 2019, the EPA remanded a part of the ELG rule to reconsider "legacy" wastewater and combustion residual leachate from landfills or settling ponds.
- Coal Combustion Residuals ("CCR") – Applies to all new and existing landfills, surface impoundments and it appears the Company has to close and remove CCR at all of its remaining surface impoundments.[80]

While the Company summarizes these regulations in the IRP Report, it does not include any discussions of the actual costs it anticipates it will have to spend to comply with these regulations or the costs that could potentially be avoided by retiring coal units early. That is not to say that DEC does not include these costs in its economic evaluations, in fact it does. However, ORS recommends that DEC provide additional tables that summarize the capital and O&M costs for environmental compliance by unit and by environmental regulation and include descriptions explaining those costs.

<u>Recommendations - CO_2 and Other Environmental Issues</u>

9. ORS recommends the Company provide tables summarizing the capital and operations and maintenance ("O&M") costs for compliance with environmental

[80] DEC 2020 IRP pg. 364.

regulations by unit and by environmental regulation, and include descriptions explaining those costs. We recommend this information be included in a modified IRP in this proceeding. **(N)**

Existing System Resources

The Company has a diverse fleet of generating units consisting of nuclear, coal, CCGT, CT, CHP, gas-fired steam turbine, hydroelectric, biomass, and solar resources. Table 10 provides a list of the Company's resources, including the probable retirement dates and the nameplate capacity of each resource based on both the winter and summer ratings.

Table 11[81]

Station	Winter (MW)	Summer (MW)	Economic Retirement Date
Nuclear Total	**5,209**	**5,065**	
Catawba[82]	458	445	2063
McGuire	2,386	2,315	2063
Oconee	2,618	2,554	2054
[redacted]	[redacted]	[redacted]	
Coal Total	**6,823**	**6,764**	
Allen	1,130	1,098	2021 - 2023
Belews Creek	2,220	2,220	2038
Cliffside	1,395	1,388	2025 - 2048
Marshall	2,078	2,058	2034
Combined Cycle Total	**2,126**	**2,016**	
Buck CC 2x1	716	668	2051
Dan River CC 2x1	718	662	2052
Lee SC CC 2x1	792	786	
Lee NCEMC Sales	-100	-100	
Combustion Turbine Total	**3,307**	**2,665**	
Lee SC CT	96	84	2047
Lincoln CT	1,565	1,193	2035
Mill Creek CT	751	563	2043
Rockingham CT	895	825	2040
Gas Fired Boiler Total	**173**	**170**	
Lee SC 3 NG	173	170	2030
Combined Heat and Power Total	**16**	**13**	
Clemson CHP	16	13	

[81] DEC 2020 IRP Appendix B, p. 201.
[82] Catawba capacity has been adjusted to reflect DEC's 19.246% ownership

Hydro Total	**1,090**	**1,090**	
Cowans Ford Hydro	324	324	
Keowee Hydro	152	152	
Lower Catawba Hydro	368	368	
Misc ROR Hydro	10	10	
Nantahala Hydro	103	103	
Upper Catawba Hydro	133	133	
Pumped Storage Total	**2,140**	**2,140**	
Bad Creek	1,360	1,360	2046
Jocassee	780	780	2068
[redacted]	[redacted]	[redacted]	
DSM Total[83]	**885**	**918**	
[redacted]	[redacted]	[redacted]	
Total Generating Capacity	**22,656**	**21,731**	

It is ORS's position that the PROSYM data is an important source of information for analysis purposes and relied on PROSYM data to create the table above. However, ORS encountered some difficulty in comparing different sources of information, as some of the PROSYM information differed when compared to other sources. For example, some of the PROSYM information was not identical to data found in the Company's Load, Capacity and Reserves table ("LCR"), which contains the peak load projection, capacity data associated with existing and new resources, and the reserve margin calculation. ORS recommends that the Company confirm that there are no inconsistencies in the modeling data. To do this, ORS recommends the Company create a cross reference table that compares each resource modeled in PROSYM, including generating units, demand response, purchase contracts, sales contracts, EE, etc. to the corresponding data in the LCR table, on a resource by resource basis. We recommend this be developed for both the Base Case with CO_2 and Base Case without CO_2 cases and cover all of the years in the study period. Also, see the Renewables section of this report below for further discussion of this issue.

<u>New Planned Additions and Uprates</u>

The Company has included in its IRP database, projects that are underway, which it also refers to as "designated projects." These projects include:[84]

[83] DEC 2020 IRP, Appendix D.
[84] List of uprates in DEC 2020 IRP Report at pg. 216. See also Table 14-B, DEC Short Term Action Plan.

- Lincoln CT project – This is a 402 MW advanced CT that was built under an unusual, discounted cost arrangement with Siemens that allows Siemens to test the unit over the next four years, at which point the unit will be turned over to DEC's full control.
- Clemson 16 MW CHP CT with heat recovery steam generation was completed in 2019 and is currently operational.
- Bad Creek uprates - 65 MW uprates per year over four (4) years of 2020-2023.
- Nuclear uprates - Catawba Units 1 and 2 units will each receive 6 MW uprates, one unit in 2021 and the other in 2022. Oconee Units 1-3 will each receive 15 MW uprates, one unit in 2022 and two units in 2023.

Relicensing

The Company is planning to relicense all eleven (11) of its nuclear resources when each unit's current Nuclear Regulatory Commission ("NRC") issued operating license expires, which will extend each unit's life by ten (10) years and will ultimately result in each unit operating for a total of 80 years. The Company first announced its relicensing plans in September 2019, when it explained that it will be required to submit NRC Subsequent License Renewal ("SLR") applications for each unit.[85] The SLR process could take up to 5 years to prepare, and to go through the review and approval process. The Oconee SLR application will be submitted first, beginning in 2021 and its licenses will expire in 2034 and 2035. While Duke Energy plans to relicense DEC's Oconee plant first, DEP's Robinson unit's operating license will actually expire earlier in 2030.

Given the impact of Duke Energy's nuclear fleet on both Companies' operations, ORS seeks additional details to be included in future IRPs regarding the Company's relicensing plans. ORS recommends that the Company supply a timeline outlining its schedule for relicensing all of its nuclear units, discuss costs it anticipates will be incurred to relicense the units, and provide details of its plans to conduct economic evaluations to assess the benefits of relicensing the units. ORS also recommend the Company provide additional insight into why it is beginning this process so far in advance of the relicensing dates for the Oconee units given that it may only take 5 year to relicense the units.

The Bad Creek Pumped Storage Hydro units are also nearing the end of their current license dates, as permitted by the Federal Energy Regulatory Commission ("FERC"). Their licenses are set to expire in 2027. The Company expects the units to have 39 years of remaining life. However, the IRP does not provide details on the relicensing status of

[85] IRP .p. 76 and https://news.duke-energy.com/releases/duke-energy-will-seek-to-renew-nuclear-plant-licenses-to-support-its-carbon-reduction-goals

these units, as required Section 58-37-40(f).[86] ORS recommends that the Company be required to provide this information in this IRP.

Retirement of Coal Units

An important component of an IRP and a specific requirement of Act 62 is that utilities must develop portfolios to fairly evaluate retirements of existing resources, such as early retirements of coal units, particularly as the utilization of those resources diminishes over time. The Company conducted a detailed coal retirement analysis in this IRP based on a three-step process:[87]

Step 1 Ranking - Coal units were ranked in order of the best potential retirement candidate to the worst recognizing that after one unit retires the benefit of retiring the next diminishes and retirements should be studied based on an iterative process. For this ranking, the Company considered age, expected capacity factor, and capacity size of the units. The Company also took into consideration the fact that some of the Allen Units are required to retire by the end of 2024 due to a settlement the Company reached with the Department of Justice in a Clean Air Act violation proceeding.[88]

Step 2 Sequential Peaker Method ("SPM") – This step was designed to determine the Company's optimal retirement dates. The SPM required running PROSYM using a base case with the studied unit operating and a second PROSYM run with the unit replaced with a peaker CT. The production cost difference between the two runs, the fixed costs of the peaker resource and the savings from early retirement of the studied coal unit were all used in the determination of the retirement cost savings. The analysis was performed for each year between 2025 and the planned retirement date of the studied unit as was modeled in the 2019 IRP.

Step 3 Portfolio Optimization – After the economic retirement dates were determined, the Company relied on the System Optimizer model to identify resources that it would need to satisfy its capacity requirements, including to fill the needs identified by retiring its coal units early as determined in Step 2.

The Company's retirement study concluded that it was economic to retire 1,676 MW of coal capacity through 2031, and another 2,078 MW of capacity in 2035.[89] The following

[86] DEC 2020 IRP pg. 209.
[87] DEC 2020 IRP, pg. 78.
[88] EPA Press Release, 9/10/2015, https://archive.epa.gov/epa/newsreleases/duke-energy-corp-reduce-emissions-power-plants-north-carolina-fund-environmental.html
[89] DEC 2020 IRP pg. 100.

table shows the retirements that the Company's economic coal retirement study determined.

Table 12
DEC Economic Coal Retirement Schedule
(2021 – 2035)

Unit	Type	Retire Year	Retire Month	Summer Capacity (MW)	Winter Capacity (MW)
Allen 2	Coal	2021	12	162	167
Allen 3	Coal	2021	12	258	270
Allen 4	Coal	2021	12	257	267
Allen 1	Coal	2023	12	162	167
Allen 5	Coal	2023	12	259	259
Cliffside 5	Coal	2025	12	544	546
Marshall 1	Coal	2034	12	370	380
Marshall 2	Coal	2034	12	370	380
Marshall 3	Coal	2034	12	658	658
Marshall 4	Coal	2034	12	660	660

In addition to the coal retirements identified in the table above, Lee Unit 3, which is a 173 MW (winter rating) gas-fired steam turbine unit is scheduled for retirement in 2031. Duke Energy's decision to retire the Allen units will affect both operating companies and appears to be reasonable in light of the current utilization of those units. The following table is based on historic data and demonstrates that the utilization of the Allen Plant has dropped significantly over the past ten years, to the point that it is no longer called on for intermediate duty, but it appears to be used strictly for peaking operation.

Table 13
Allen Plant Units 1 -5[90]

	Annual Generation (MWH)	Annual Capacity Factor (%)
2010	5,473,381	55%
2013	2,004,449	20%
2016	1,391,068	14%
2019	895,019	9%

In the 2019 IRP, the Company assumed that coal units would retire consistent with the retirement dates found in the Company's depreciation study that was used in its prior rate case.[91] Exhibit 1 below provides a list of important retirements and additions in the 2019 IRP, compared to the important dates in this IRP. The result is that the Allen units, which previously were all planned to retire between 2025 and 2029, are now moved up to retire between 2022 and 2024. In addition, DEP's Cliffside Unit 5, which previously was planned to retire in 2033, has now been moved up to retire in 2026.

While the Company's modeling assumptions assume specific retirement dates, there are uncertainties as to when those retirements will actually occur. For instance, for modeling purposes, Allen Units 2 - 4 are assumed to retire in January 2022, which is less than a year away. Although the retirements of these Allen Units appear in the Company's Short-Term Action Plan as depicted in Table 14-B of the IRP, the Company has repeatedly stated that:

> ….this is not a commitment to retire the Allen units on this timeline but rather contains the Company's most recent estimate of retirement economics at the time of this filing. Official retirement will require final management approval with final retirement dates contingent upon the finalization of the supporting switchyard project and other operational considerations.[92]

This is an important issue since there is less than a year until some of the Allen units are to be retired. ORS recommends the Company provide additional clarity regarding its plans for the retirement of the Allen units, including details about the switchyard and any

[90] EIA 923 Data at https://www.eia.gov/electricity/data/eia923/
[91] DEC 2019 IRP Report, pg. 54.
[92] DEC 2020 IRP pg. 83.

other required transmission upgrades, an explanation of the steps being pursued to receive final approval within the Company and from any regulatory body, and a timeline for conducting these activities.

ORS has one other concern that relates to the Company's retirement study. Step 2 was conducted using the SPM that relied on production cost runs. In one run, the studied coal unit was operated and in the other the studied unit was retired and a peaker unit was included as a replacement. Though the Company asserted that Step 2 determined the "optimal date for retirement", it is not clear this is necessarily true since the Company did not perform an optimization analysis to compare the retirement resources to optimal replacements. Instead, it simply assumed that the replacement to the studied unit would be a peaker unit. Only after the retirement date was determined and locked-in, did the Company run its optimization model to determine the optimal replacement resources. ORS recommends that the Company provide an explanation why it did not use its optimization model, System Optimizer, to conduct Step 2 of the retirement study, especially given that the System Optimizer is capable of conducting retirement analyses. In addition, ORS recommends that the Company be required to demonstrate that the SPM method did not derive different and less optimal retirement dates than what would have been derived had the Company's optimization model been used in Step 2.

Recommendations - Existing System Resources

10. To ensure there are no inconsistencies in modeling data, we recommend the Company create a cross reference table that compares each resource modeled in PROSYM, including generating units, demand response, purchase contracts, sales contracts, EE, etc. to the corresponding data in the Load, Capacity and Reserves ("LCR") table, on a resource by resource basis. We recommend this be developed for both the Base Case with CO_2 and Base Case without CO_2 cases, and cover all of the years in the study period. We recommend this information be provided in a modified IRP in this proceeding. **(N)**

11. Recognizing that the Company plans to pursue relicensing of the Oconee nuclear units' operating licenses in 2021, we recommend the Company supply additional information regarding its relicensing plans (including a timeline) and its plans to conduct economic evaluations to assess the benefits of relicensing the units. We recommend the Company provide additional insight into why it is beginning this process so far in advance of the relicensing dates. We recommend this information be provided in a modified IRP in this proceeding. **(N)**

12. The Bad Creek Pumped Hydro units' licenses are set to expire in 2027. However, the IRP does not provide details on the relicensing status of these units. Since these

units will need to go through a relicensing process with FERC soon, we recommend that DEC provide the status of its plans to relicense the units, including any actions it will have to take as part of the relicensing process and any costs that it will incur to relicense the units. We recommend this information be provided in a modified IRP in this proceeding. **(N)**

13. ORS recommends DEC provide additional clarification regarding its plans for the retirement of the Allen units, including details about any transmission impacts, an explanation of the steps being pursued to receive final approval within DEC and from any regulatory body, and a timeline for conducting these activities. We recommend this information be provided in a modified IRP in this proceeding. **(N)**

14. ORS recommends the Company provide evidence that the optimal retirement dates that were determined with the Sequential Peaker Method ("SPM") are comparable to the optimal retirement dates the System Optimizer model would produce if it were used in the retirement study. We recommend this information be provided in a modified IRP in this proceeding. **(N)**

Generic Resource Options

The Company reflected two categories of new resources in the six Portfolios that it modeled in its IRP. The first category of new resources were "forced-in," in other words, they were either added because they were already under contract, they were required pursuant to federal law and/or North Carolina statutory or regulatory requirements, or they were selected based on a desire to reduce carbon emissions.[93] Additional discussion of these forced-in resource types is found in the next section, Renewables.

The second category of new resources were selected from a list of generic resource options based on the economics of the resource, pursuant to a least cost criterion. The Company considered a wide range of technology options, including technologies that are not yet mature and/or available. The Company assembled assumptions associated with each of the generic resources, including capital costs, physical operating and other performance characteristics, emissions rates, fuel expenses, variable and fixed non-fuel O&M expenses, and other capital-related expenses, such as depreciation (based on estimated service or book lives), property taxes, and insurance. The Company relied on actual historic information, and/or forecast information based on trends in the Company's historic cost and performance data. It also relied on vendor cost and performance data,

[93] NC PSDR 3-14 defines "Base Solar" as "artificially added that represents both designated and mandated solar. Additionally, some undesignated solar, representing opportunities under SC Act 62 and assumptions regarding materialization of projects from the T&D queues, was also included in each portfolio." We presume this category is all forced, with mandated, designated, and undesignated represented within it.

and used data from other sources, such as the Electric Power Research Institute ("EPRI") Technical Assessment Guide, and Energy Information Administration ("EIA") information.

The Company considered more than sixty potential generic capacity resource types in its evaluation. To narrow the potential resource options down to a more manageable list, the Company first performed a Technical Screening Analysis that considered factors such as the status of development, environmental acceptability, fuel availability, commercial availability, and service territory feasibility. The Company provided explanations for eliminating certain resources based on its Technical Screening Analysis as follows:[94]

- Fuel cells – cost and performance issues limited use to niche markets and/or subsidized installations.
- Geothermal - no suitable sites in the region.
- Small Modular Reactors ("SMR") - lack of commercial availability. However, while SMRs were screened out, the Company did consider them in portfolios where high CO_2 emissions constraints were considered.
- Advanced Nuclear Reactors - expected availability not before the 2030 time period.
- Poultry waste and swine digesters – expensive, and operational and permitting challenges exist.
- Solar Steam Augmentation in a fossil generating plan – not economic compared to Solar PV.
- Supercritical CO_2 Brayton Cycle using CO_2 instead of H_2O – advanced technology which is not presently commercially available.
- Hydrogen – although promising, it is not presently commercially available.
- Compressed Air Energy Storage ("CAES") – proven, but overly expensive.
- Off-Shore Wind - high cost. Even though these were screened out, they were considered in some portfolios.

The Company further narrowed down the list of potential resource options based on an economic screening process. For this process, technology types were grouped within categories, including baseload, peaking/intermediate, renewable, and storage. DEC's IRP Table 8A identifies each of the resource types that were evaluated separately in these four categories.

DEC's economic screening analysis was strictly a relative cost comparison of similar resource types and did not include production cost dispatch modeling. The analysis used a screening curve, or "busbar curve,"[95] approach that first required the capital revenue

[94] DEC 2020 IRP, pg. 316.
[95] Response to NCPS 13-1, consisting of an Excel workbook.

requirement on a PVRR basis for each technology type to be derived. Then the PVRR cost was levelized on a dollar per kilowatt-year ($/kW-year) basis over the operating life of the technology type. Finally, fuel costs, emissions costs, and non-fuel O&M expenses, were calculated at different assumed levels of capacity factor for the technology type and those costs were added to the PVRR cost. The final screening curve result was a cost function that varied over a range of capacity factors that the technology type could operate.

One resource whose screening curve is found to be higher than another over the entire range of capacity factors is considered to be more expensive than the other resource. The higher cost resource can then be "screened out" or eliminated from further modeling consideration. All remaining resources are passed on to the next stage of the analysis, which is a more detailed economic evaluation that relies on expansion plan optimization and production cost modeling. This screening process is an industry standard practice that is typically performed by utilities in IRPs. The following are the resources that DEC evaluated in its economic screening curve analyses.[96]

Non-Renewable Resources

- CTs, including 15 MW, 192 MW, 752 MW, and 913 MW sized alternatives of CT types.
- Reciprocating Engines, including 18 MW and 201 MW alternatives.
- CCGTs, with and without duct firing, including 601 MW and 1,224 MW alternatives.
- Coal with Carbon Capture and Sequestration ("CCS"), including a 782 MW alternative.
- Integrated Gasification Combined Cycle ("IGCC") with CCS, including 557 MW alterative.
- Nuclear, including 12 SMRs, 720 MW Total, and 2 AP1000s, 2,234 MWs Total.
- CHP, including 9 MW and 21 MW alternatives.

Renewable Resources

- Onshore and Offshore Wind, including 150 MW Onshore, and 600 MW Offshore alternatives.
- Fixed and Single Axis Tracking ("SAT") Solar PV, including 75 MW alternatives of both types.
- Landfill Gas, including a 5 MW alternative.

[96] DEC 2020 IRP, pg. 326.

- Wood-fired Bubbling Fluidized Bed ("BFB") Boiler, including a 75 MW alternative.

Storage Technologies

- Pumped Storage Hydro ("PSH"), including a 1,400 MW alternative.
- Lithium-Ion ("Li-Ion") Batteries, including:
  - 10 MW, 10, 20, and 40 MWh alternatives.
  - 50 MW, 200 and 300 MWh alternatives.
- Flow Batteries, including a 20 MW, 160 MWh alternative.
- Advanced CAES, including a 250 MW alternative.
- Hybrid Renewable and Storage, including a 75 MW SAT Solar PV with a 20 MW, 80 MWh Li-Ion Storage alternative.

The Company's baseload technology screening curve comparison is shown graphically on page 332 of its IRP, and the results suggest that natural gas fired resources and CHP resources are among the lowest cost all of the technology types considered.

ORS has one concern about CHP modeling. While it appears that CHP was found to be reasonably economic compared to the other alternatives, at least based on the Company's economic screening curve analysis, it is not clear if DEC modeled CHP resources as selectable resources in the economic optimization process. However, it does appear that DEC selected CHP resources as they were included in DEC's short term action plan in 2022 (30 MW), and in 2023 (30 MW). ORS recommends that DEC supply additional information in the IRP explaining the basis for how CHP were added to the short-term action plan, and explain why CHP resources were not treated as selectable resources in the economic optimization process, if in fact they were not. The Company's peaking technology screening results (page 333 of DEC's IRP) suggest that frame sized CTs without selective catalytic reduction technologies ("SCR") are the most economic resources compared to aeroderivative CTs and reciprocating engine generating units.

To evaluate the reasonableness of the Company's generic resource assumptions, ORS developed the following table that compares various assumptions for the Company's generic resources to assumptions for similar generic resources found in other publicly available sources. In addition to the Company's data, the table includes data from Virginia

Electric and Power Company,[97] Kentucky Power Company,[98] Southwestern Electric Power Company,[99] DESC 2020 IRP,[100] EIA's 2020 Annual Energy Outlook ("AEO") report,[101] Lazard's 2019 Levelized Cost of Energy Analysis,[102] National Renewable Energy Lab ("NREL"),[103] the NRC[104]. The table includes information, to the extent it was applicable and/or available, for capacity, book life, capital cost, fixed and variable O&M expenses, average heat rate, capacity factor, and levelized cost of energy ("LCOE") for six generic resource types.

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97 Appendix 5N – Busbar Assumptions; Appendix 5M – Tabular Results of Busbar; Virginia Electric and Power Company's 2020 Integrated Resource Plan. https://www.dominionenergy.com/-/media/pdfs/global/2020-va-integrated-resource-plan.pdf?la=en&rev=fca793dd8eae4ebea4ee42f5642c9509

98 New Generation Technology Options with Key Assumptions, Exhibit D, p. 204, Kentucky Power 2019 Integrated Resource Planning Report; https://psc.ky.gov/pscecf/2019-00443/sebishop%40aep.com/12202019120748/KPCO_2019_IRP_Volume_A_Public_Version.pdf

99 New Generation Technologies, Part III; Exhibit B, p.149; Description of Studies & Study Assumptions. https://lpscpubvalence.lpsc.louisiana.gov/portal/PSC/DocumentDetails?documentId=131242https://lpscpubvalence.lpsc.louisiana.gov/portal/PSC/DocumentDetails?documentId=131242

100 Dominion Energy SC 2020 IRP Report, pg. 46. https://dms.psc.sc.gov/Attachments/Matter/0f53757a-4334-4fb8-81d4-00ca3b71d5e5

101 Cost and Performance Characteristics of New Generating Technologies; U.S. Energy Information Administration's Annual Energy Outlook 2020. https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf

102 Lazard's Levelized Cost of Energy Analysis – Version 14.0. https://www.lazard.com/media/451419/lazards-levelized-cost-of-energy-version-140.pdf

103 NREL 2020 ATB, https://atb.nrel.gov/electricity/2020/data.php

104 US NRC Replacement Energy Cost Estimates 2020, pg. 36. https://www.nrc.gov/docs/ML2034/ML20342A132.pdf

Table 14
Generic Resource Comparison

Combustion Turbine

	DEC & DEP	DESC	NREL (Low)	NREL (High)	Virginia Power	Kentucky Power	SWEPCO	Lazard (Low)	Lazard (High)	EIA AEO2020	NRC
Capacity (MW)	[redacted]	523				490	490	240	50	237	237
Book Life (yrs)	[redacted]		30	30	36			20	20		
Capital Cost ($/kW)	[redacted]	$ 469	$ 1,018.39	$ 1,018.39	$ 562	$ 673	$ 757	$ 675	$ 875	$ 661	$ 691
Fixed O&M ($/kW-yr)	[redacted]	$ 5.66	$ 11.80	$ 11.80		$ 24.99	$ 25.24	$ 7.25	$ 22.75	$ 7.10	$ 7.26
Variable O&M ($/MWh)	[redacted]	$ 0.34	$ 4.66	$ 4.66		$ 6.38	$ 6.38	$ 4.25	$ 5.75	$ 4.56	$ 11.42
Average Heat Rate (MBTU/MWh)	[redacted]	9,364	9,515	9,515	9,670	10,000	10,000	9,800	8,000	9,905	9,550
Capacity Factor (%)	[redacted]		30%	12%		25%	25%	10%	10%	30%	
LCOE	[redacted]		$ 57.57	$ 96.89		$ 119.31	$ 117.99	$ 151.00	$ 198.00	$ 69.95	

Combined Cycle

	DEC & DEP	Virginia Power	NREL (Low)	NREL (High)	Kentucky Power	SWEPCO	Lazard (Low)	Lazard (High)	EIA AEO2020	NRC
Capacity (MW)	[redacted]				1230	1230	550	550	1083	1100
Book Life (yrs)	[redacted]	36	30	30			20	20		
Capital Cost ($/kW)	[redacted]	$ 1,102	$ 1,127	$ 2,878	$ 673	$ 662	$ 650	$ 1,150	$ 885	$ 796
Fixed O&M ($/kW-yr)	[redacted]		$ 13.32	$ 27.96	$ 10.84	$ 10.84	$ 14.50	$ 18.50	$ 12.37	$ 10.67
Variable O&M ($/MWh)	[redacted]		$ 2.24	$ 5.93	$ 1.58	$ 1.58	$ 2.75	$ 5.00	$ 1.89	$ 2.13
Average Heat Rate (MBTU/MWh)	[redacted]	6,590	6,401	7,525	6,200	6,200	6,150	6,900	6,370	6,300
Capacity Factor (%)	[redacted]		87%	55%	75%	75%	70%	50%	87%	
LCOE	[redacted]		$ 30.34	$ 66.06	$ 57.11	$ 54.77	$ 44.00	$ 73.00	$ 37.27	

Battery Energy Storage

	DEC & DEP	DESC	NREL	Virginia Power	Kentucky Power	SWEPCO	EIA AEO2020	NRC
Capacity (MW)	[redacted]	100		30	10	10	50	30
Book Life (yrs)	[redacted]		15	10				
Capital Cost ($/kW)	[redacted]	$ 1,911	$ 1,692	$ 2,224	$ 1,828	$ 1,797	$ 1,454	$ 1,861
Fixed O&M ($/kW-yr)	[redacted]	$ -	$ 42.30		$ 39.69	$ 39.69	$ 25.14	$ 37.63
Variable O&M ($/MWh)	[redacted]	$ -	$ -		$ -	$ -	$ -	$ 7.52
Capacity Factor (%)	[redacted]		17%	15%	25%	25%		
LCOE	[redacted]				$ 159.93	$ 159.11		

Onshore Wind

	DEC & DEP	Virginia Power	NREL (Low)	NREL (High)	SWEPCO	Lazard (Low)	Lazard (High)	EIA AEO2020	NRC
Capacity (MW)	[redacted]				200	175	175	200	100
Book Life (yrs)	[redacted]	25	30	30		20	20		
Capital Cost ($/kW)	[redacted]	$ 1,926	$ 1,814	$ 2,963	$ 1,135	$ 1,050	$ 1,450	$ 1,530	$ 1,513
Fixed O&M ($/kW-yr)	[redacted]		$ 44.77	$ 44.77	$ 45.81	$ 27.00	$ 39.50	$ 26.69	$ 53.33
Variable O&M ($/MWh)	[redacted]		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capacity Factor (%)	[redacted]	40%	52%	16%	44%	55%	38%	40%	
LCOE	[redacted]		$ 29.34	$ 131.82	$ 15.88	$ 26.00	$ 54.00	$ 34.71	

Offshore Wind

	DEC & DEP	Virginia Power	NREL (Low)	NREL (High)	Lazard (Low)	Lazard (High)	EIA AEO2020
Capacity (MW)	[redacted]				210	385	400
Book Life (yrs)	[redacted]	25	30	30	20	20	
Capital Cost ($/kW)	[redacted]	$ 2,952	$ 4,212	$ 7,100	$ 2,600	$ 3,675	$ 4,989
Fixed O&M ($/kW-yr)	[redacted]		$ 128.46	$ 103.60	$ 67.25	$ 81.75	$ 111.51
Variable O&M ($/MWh)	[redacted]		$ -	$ -	$ -	$ -	$ -
Capacity Factor (%)	[redacted]	42%	44%	30%	52%	48%	45%
LCOE	[redacted]		$ 100.39	$ 206.35	$ 69.00	$ 104.00	$ 117.11

Utility Solar

	DEC & DEP	DESC	Virginia Power	SWEPCO	Lazard (Low)	Lazard (High)	EIA AEO2020	NREL (Low)	NREL (High)	NRC
Capacity (MW)	[redacted]	100		50	150	150	150			150
Book Life (yrs)	[redacted]		35		30	30		30	30	
Capital Cost ($/kW)	[redacted]	$ 1,151	$ 1,363	$ 1,419	$ 975	$ 825	$ 1,327	$ 1,658	$ 1,658	$ 973
Fixed O&M ($/kW-yr)	[redacted]	$ -		$ 15.27	$ 13.50	$ 9.50	$ 15.46	$ 19.44	$ 19.44	$ 8.12
Variable O&M ($/MWh)	[redacted]	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capacity Factor (%)	[redacted]		25%	28%	34%	21%	30%	35%	22%	
LCOE	[redacted]	$ 47.77	$ 58.36	$ 51.71	$ 31.00	$ 42.00	$ 30.94	$ 30.21	$ 48.70	

Conclusions – Generic Resources

The Company's assumptions generally appear to be reasonable for many of the generic resource type assumptions, when compared to the other sources of data. There are, however, some items that warrant additional consideration.

In the CT comparison, DEC's capital cost assumption appears to be low compared to the other data, except for Dominion Energy (both Virginia Power and South Carolina). It should be noted, that in the DESC's 2020 IRP, DESC was criticized for the fact that its CT capital cost assumption appeared to be too low. DESC explained that it based its assumption on a volume discount that was available to its company; however the availability of such discounts over the long-term was disputed, and in the ordering paragraphs of the DESC 2020 IRP Order, the Commission ordered DESC to "use industry accepted ICT capital cost assumptions, such as NREL."[105] ORS recommends that DEC provide additional justification for its CT capital cost assumption.

In the Battery Energy Storage comparison, DEC's capital cost assumption appears to be at the high end of the range of estimates, though its cost is not the highest compared to all of the other sources. However, DEC's fixed O&M estimate appears to be out of line

[105] PSCSC December 23, 2020, Order No. 2020-832, DESC 2020 IRP, Docket No. 2019-226-E, pg. 90, Ordering Paragraph v.

with the other estimates and ORS recommends that DEC provide additional justification for its fixed O&M cost assumption. Also, DEC's capacity factor assumption appears to be too low compared to the other available sources, and ORS recommends that DEC provide additional justification for its capacity factor assumption, which may also explain why DEC's LCOE value is so high compared to the other sources.

It is ORS's position that the Company's utility scale solar capital cost and fixed O&M cost assumptions warrant additional consideration. Though DEC's capital cost assumption could hardly be considered out of line when compared to the other utility forecasts, its ultimate LCOE cost appears to be high relative to the other estimates. This leads to a question as to whether the utility's assumed revenue requirement for a solar resource is the only solar resource option assumption that should be evaluated in an IRP. In its recent DESC 2020 IRP Order, the Commission found that:[106]

> The parties provided ample testimony that solicitation of solar and/or storage resources via a competitive solicitation has the potential to create opportunities for ratepayer savings, by allowing the utility to procure energy from such resources more cheaply than it can generate it.

Part of the evidence that the Commission cited to in reaching this conclusion was the South Carolina Solar Business Alliance's testimony that DEC's own solicitation in North and South Carolina resulted in the procurement of solar resources at an average price of \$38/MWh,[107] which is far lower than the LCOE of \$[redacted]/MWh that appears in the table above for DEC's generic solar resource. ORS recommends the Company include an additional solar generic resource option in its IRP modeling that reflects the kind of solar PPA prices that may be available in the market.

ORS has one final Generic Resource conclusion, which relates to the Company's capacity value assumptions for standalone solar and solar plus battery storage resources. As discussed in the Resource Adequacy – Reserve Margin Issues section above, Astrapé derived capacity value assumptions based on a SERVM model analysis. These capacity values represent the percentage of installed nameplate capacity that contributes to meeting peak loads in the summer and winter, and since the winter peak drives the need for capacity, the winter capacity values of solar and solar plus battery are of the main importance.

The Company used a 1% winter capacity value for standalone solar and a winter capacity value of 25% for solar plus battery energy storage, based on an assumed 4-hour

[106] *Id*. pg. 85.
[107] *Id*. pg. 47.

discharge assumption. Given the importance that this assumption has on the IRP analysis, ORS recommends that further investigation be conducted regarding these values. One investigation that could be performed would be to assess the impact on the Company's base case resource plan if higher winter capacity value ratings were assumed such as 5% for solar and 30% for solar plus battery energy storage. This investigation should be discussed in a future IRP as part of the Company's stakeholder engagement process.

Recommendations - Generic Resource Options

15. ORS recommends the Company supply additional information explaining the basis for how CHP resources were added to the short-term action plan, and explain why CHP resources were not treated as selectable resources in the economic optimization process, if in fact they were not. We recommend this information be provided in a modified IRP in this proceeding. **(N)**

16. ORS recommends DEC provide additional justification for its Combustion Turbine ("CT") capital cost assumption. We recommend this information be provided in a modified IRP in this proceeding. **(N)**

17. ORS recommends DEC provide additional justification for its Battery Energy Storage fixed O&M cost and capacity factor assumptions. We recommend this information be provided in a modified IRP in this proceeding. **(N)**

18. ORS recommends the Company include an additional solar generic resource option in its IRP modeling assumptions that reflects the kind of solar purchase power agreements ("PPA") prices that may be available in the market. As a proxy, the Company could assume $38/MWh as the solar PPA cost. We recommend this be addressed in a modified IRP in this proceeding. **(N)**

19. Given the importance that solar capacity values and solar plus battery energy storage capacity values potentially could have on the IRP analysis, ORS recommends that further investigation be conducted regarding these values with stakeholder input, discussed as part of a stakeholder engagement process. One investigation that could be performed would be to assess the impact on the Company's base case resource plan if higher winter capacity value ratings were assumed such as 5% for solar and 30% for solar plus battery energy storage. We recommend this be addressed in the future through the Company's stakeholder process. **(L)**

Renewables

DEC's detailed economic evaluations of its six (6) Portfolios considered several types of renewable resources including Solar, Battery Energy Storage, Solar plus Battery Energy Storage, Offshore Wind, Central-US Wind, and Pumped Hydro. Both solar and battery energy storage made up a sizable percentage of renewable resources that were added in each of the portfolios. The Company's IRP resulted in new resources being added by either being "forced-in" or selected based on its optimization process. The Company further grouped resources that were forced-in into three categories that it refers to as "Designated", "Mandated" and "Undesignated" resources.

Designated, Mandated, and Undesignated Resource Categories

Mostly, these categories apply to renewable resources, but they also apply to other types of resources as well. The definitions of these categories are:

- **Designated Resources -** owned resources that DEC has already committed to add or third party owned resources that are already connected or will be connected but have a signed PPA.
- **Mandated Resources -** resources that are not yet under contract but are required under statutory or regulatory requirements.
- **Undesignated** – resources that are neither designated nor mandated. This includes solar resources that will be added upon expiration of designated solar contracts as replacement resources.

Examples of designated and mandated resources include various renewable resources, but they also include nuclear uprates, the Bad Creek runner upgrades, and the Clemson CHP project.

Many of the mandated, designated and undesignated resources that will be added to the system are solar resources, and Figure 5-A on pg. 44 of the Company's IRP Report contains a graph showing mandated, designated, and undesignated solar resources.

Mandated solar stems from a combination of federal and state statutory and regulatory requirements. The different categories of requirements are detailed in ORS AIR 2-6 and Table 15 below, but we point out that certain North Carolina statutes require more renewable resources to be added than would otherwise be required in South Carolina. For example, NC House Bill 589 requires both DEC and DEP to procure capacity in the aggregate amount of 2,660 MW ("initial Targeted Amount") from renewable resources through a competitive procurement program known as the North Carolina CPRE, which requires capacity be acquired over a term of 45 months in tranches starting from February 2018.

As far as acquiring the remainder of the CPRE capacity, the Company states that acquisition of the remaining capacity will depend on the final results of Tranche 2, as well as the continued increases in capacity that the Company referred to in its IRP Report as "Transition MW". DEC defined transition MWs as the total capacity of renewable generation projects in the combined Duke Balancing Authority area that are 1) already connected, or 2) have entered into PPAs and interconnection agreements (IAs) as of the end of the 45-month competitive procurement period, and which are not subject to curtailment or economic dispatch. The CPRE capacity will be reduced by the amount of excess Transition MWs that DEC and DEP combined will have.

Table 15[108]
Base Case With CO_2

DEC Solar Capacity	NC Greensource	HB589	PURPA/ Act 62	CPRE	Act 236	SC Greensource Advantage	Utility Owned	Future Growth	Total DEC Capacity
2021	104	0	647	95	38	0	83	0	966
2022	103	42	724	434	40	0	98	0	1,442
2023	89	176	836	533	40	11	122	0	1,807
2024	74	271	907	681	40	45	121	0	2,139
2025	72	336	909	829	40	79	121	75	2,460
2026	71	401	910	926	40	112	120	150	2,729
2027	71	400	1,006	921	39	112	119	374	3,042
2028	71	399	1,101	916	39	111	119	597	3,353
2029	70	398	1,195	912	39	111	118	894	3,738
2030	70	397	1,189	907	39	110	118	1,190	4,020
2031	70	396	1,183	903	39	110	117	1,484	4,300
2032	0	394	1,247	898	38	109	116	1,776	4,579
2033	0	393	1,241	894	38	108	116	2,067	4,858
2034	0	393	1,234	889	38	108	115	2,357	5,135
2035	0	392	1,228	885	38	107	115	2,645	5,410

Table 15 above, includes Future Growth solar resources, which appear to be the economically selected resources in DEC's IRP. The table shows that by 2035, economically selected resources will account for approximately 48% (2,645/5,410) of the total solar resources that will be added to DEC's system by 2035, and the rest, which appear to be forced-in resources will amount to approximately 52% (2,765/5,410) of the

[108] ORS AIR 2-6d. Note that the actual CPRE forecast of 1,860 MW cannot be discerned from ORS AIR 2-6d. DEC would have to supply additional information to identify the CPRE MWs.

solar resources that will be added to DEC's system. It is not clear how much of this forced-in solar capacity would have been selected by an optimization model in the absence of these mandates.

ORS has presented one estimate of the amount of the solar resources that will be added to DEC's system over the planning horizon; however, the Company also supplied other data in other discovery responses that we found to be inconsistent. For instance, the amount of "mandated" annual solar resource additions shown in DEC's IRP Report in Figure 5-A do not seem to be consistent with the amounts that can be discerned from ORS AIR 2-6. For this section, ORS ultimately relied on the data that was provided in ORS AIR 2-6, because it provided the level of detail that ORS needed for its evaluation. The Company's response to NC PSDR 7-1 provides another example of renewable resource capacity addition results that do not appear to match with the data that was supplied in ORS AIR 2-6. The interrelationships between forced/economic resource additions, and between designated/mandated/undesignated renewable resources are unclear. ORS recommends that the Company provide a table identifying each renewable resource option that was modeled, whether the resource was forced-in or economically selected and the process by which it was economically selected (System Optimizer or other approach), the reason the resource was forced-in (e.g. CPRE, Act 236, etc.), whether the resource is a designated, mandated, or undesignated resource, and where the resource is found in the PROSYM database and in the LCR tables for reconciliation purposes. Ultimately, data supplied in tables, figures and discovery responses should be consistent.

Recommendations - Renewables

20. ORS recommends the Company provide a table identifying each renewable resource option that was modeled, and include whether the resource was forced-in or economically selected (System Optimizer or other approach), the reason the resource was forced-in (e.g. Competitive Procurement of Renewable Energy Program ("CPRE"), Act 236, etc.), whether the resource is a designated, mandated, or undesignated resource, and where the resource is found in the PROSYM database and in the LCR tables for reconciliation purposes. We recommend this information be provided in a modified IRP in this proceeding. **(N)**

Resource Planning

Summary of Base and Other Portfolios

The Company's 2020 IRP includes six portfolios, or potential "pathways," that attempt to reflect and assess how the Company's resource portfolio may evolve over the 15-year study period (2021 through 2035) based on current data and assumptions across a spectrum of potential futures.[109] The following summarizes the portfolios that were considered:

Portfolio A - Base Case Without CO_2 - Economic coal retirement dates, no CO_2 policy.

Portfolio B - Base Case With CO_2 - Economic coal retirement dates, with CO_2 policy.

Portfolio C - Earliest practicable coal retirement dates.

Portfolio D - 70% CO_2 Reduction High Wind – Earliest practicable coal retirement dates, relying on more wind resources (on-shore and off-shore).

Portfolio E - 70% CO_2 Reduction High SMR – Earliest practicable coal retirement dates, relying on small modular reactors.

Portfolio F - No New Gas – Economic coal retirement dates, replaces economic additions of natural gas units with battery storage and renewable resources.

The Company recognizes that it is obligated to develop an IRP based on the policies in effect at this time, and accordingly, Portfolio A reflects existing environmental policies and represents the most economic scenario of the six Portfolios on a present value revenue requirement and non-risk adjusted basis. To assess the impact that potential new federal and state policies may have on future resource additions and in response to stakeholder feedback, the Company's 2020 IRP includes five other portfolios (B through F) that were developed to achieve sequentially greater levels of carbon emission reductions.

Portfolios B through F go beyond the regulatory policies and statutory requirements in effect at this time and provide insight into the effects of potential changes in those policies and statutory requirements over the study period. Factors that will influence the adoption of Portfolios B through F include the pace of carbon reduction goals, technology availability and commercial maturation, reliability and other operational considerations, and cost to customers. These portfolios address the most economic and earliest practicable paths for coal retirement; acceleration of renewable technologies including solar, battery and pumped-hydro energy storage, onshore and offshore wind; integration of renewable resources; expanded implementation of energy efficiency and demand response; and deployment of new zero-emitting load following resources (ZELFRs), such as SMRs.

Portfolios A, B, and F rely on the economic coal retirement date assumptions, which include retirements of DEC's coal-fired resources in 2022, 2024, 2026, 2031, and 2035,

[109] A summary of the resource additions reflected in each of the six portfolios were provided by DEC and DEP in response to NCPS DR7-1.

resulting in cumulative retirements of 3,754 MW (winter ratings),[110] over the 15-year study period.[111] Portfolios C through E rely on accelerated coal retirement dates, which are accelerated to the earliest practicable dates in order to address more aggressive potential carbon reduction targets. With the exception of Cliffside Unit 6, all coal units are assumed to retire prior to 2030. Cliffside Unit 6 switches to 100% natural gas by 2030.

The following table presents the incremental resources that were selected in DEC's planning process for each of the six (6) portfolios over the 2021 – 2035 time period. The table separates the incremental resource additions by those that DEC forced-in to its database without having selected them through an economic optimization process (also referred to as Base resources), and by resources that DEC selected economically based on its optimization process.

Table 16
Comparison of Incremental Resources Added (MW)
Categorized by Forced-In Resources and Economically Selected Resources
By Portfolio (2021 - 2035)

Forced-In Resources	**A**	**B**	**C**	**D**	**E**	**F**
Solar	1,981	1,981	1,981	3,284	3,284	3,284
Solar + Storage	739	739	739	1,794	1,794	1,794
Grid-Tied 4hr Batteries	161	161	161	161	161	2,195
Grid-Tied 6hr Batteries						311
Grid-Tied 8hr Batteries						
Offshore Wind				1,400	138	138
Oklahoma Wind				801	638	638
Nuclear SMR					684	684
Bad Creek PH2					1,620	1,620
Total Forced-In Resources	2,881	2,881	2,881	7,440	8,319	10,664

Economically Selected Resources	**A**	**B**	**C**	**D**	**E**	**F**
Solar		1,275	1,275	1,725	1,725	1,650
Solar + Storage		975	975	675	675	750
On-Shore Wind		150		300	300	600

[110] DEC 2020 IRP Tables 12-F and 12-G.
[111] *Id*.

CC	2448	2448	2448	2448	1224	
CT	3199	2285	4570	1828	2742	
Total Economically Selected Resources	5,647	7,133	9,268	6,976	6,666	3,000

Total Incremental Resources Added	8,528	10,014	12,149	14,416	14,985	13,664

The following table is similar to the table above, but it sums together the forced-in and economically selected resources by category.

Table 17
Comparison of Incremental Resources Added (MW)
By Portfolio (2021 - 2035)

Total Incremental Resources Added	**A**	**B**	**C**	**D**	**E**	**F**
Solar	1,981	3,256	3,256	5,009	5,009	4,934
Solar + Storage	739	1,714	1,714	2,469	2,469	2,544
Battery Energy Storage	161	161	161	161	161	2,506
Offshore Wind		150		2,501	1,076	1,376
Nuclear SMR					684	684
Bad Creek PH2					1,620	1,620
CC	2448	2448	2448	2448	1224	
CT	3199	2285	4570	1828	2742	
Total Incremental Resources Added	8,528	10,014	12,149	14,416	14,985	13,664

The following provides additional descriptions of the six (6) Portfolios.

Portfolio A (Base Case without Carbon)

The Company's Portfolio A is the Base Case without CO_2 plan. In addition to the retirements of existing coal-fired resources, it features additions of new "base" solar resources, starting in 2021 and each year thereafter which result in cumulative additions of 1,981 MW through 2035. Additionally, there are "base" solar + storage resources, which result in cumulative additions of 739 MW through 2035. Also included are small additions of new "grid-tied 4-hour batteries" in 2021 and each year thereafter through 2026, resulting in cumulative incremental additions of 161 MW through 2035. Portfolio A also includes additions of new gas-fired combustion turbine resources in 2028, 2029, 2032, 2034, and 2035, resulting in cumulative additions of 3,199 MW, and additions of 2,448 MW of new gas-fired combined cycle resources in 2034.

Portfolio B (Base Case with Carbon)

Portfolio B is the same as Portfolio A, which uses the economic coal retirement schedule, but it incorporates a carbon tax starting at $5 per ton in 2025, escalating at $5 per ton annually thereafter, which makes additional renewables resources economical, and delays and displaces new gas-fired resources. It includes:

1. same base solar, base solar + storage, and grid-tied 4-hour batteries as in Portfolio A.
2. 1,275 MW of new solar additions starting in 2024 and each year thereafter through 2035.
3. 975 MW of new solar + storage additions starting in 2028 and each year thereafter through 2035.
4. 150 MW of new onshore wind in 2034,
5. delays in additions of new gas-fired combustion turbine resources to 2029, 2030, 2034, and 2035, resulting in cumulative additions of 2,285 MW,
6. delays in additions of new gas-fired combined cycle resources to 2034 and 2035, resulting in cumulative additions of 2,448 MW

Portfolio C (Earliest Practicable Coal Retirements)

Portfolio C is the same as Portfolio B, except that it reflects accelerated retirements of existing coal-fired resources, accelerated and incremental additions of new renewables resources, and accelerated and incremental additions of new gas-fired combustion turbines and combined cycle resources. It includes:

1. same base solar, base solar + storage, and grid-tied 4-hour batteries as in Portfolio A.
2. incremental additions of new solar resources starting in 2024 and each year thereafter through 2035, resulting in cumulative incremental additions of 1,275 MW.
3. incremental additions of new solar + storage resources starting in 2028 and each year thereafter through 2035, resulting in cumulative incremental additions of 975 MW.
4. delay of new onshore wind resources until after 2035.
5. acceleration in additions of new gas-fired combustion turbine resources to 2027, 2028, 2030, 2033, and 2035, resulting in cumulative additions of 4,570 MW.
6. additions of new gas-fired combined cycle resources in 2027 and 2028, resulting in cumulative additions of 2,448 MW.

Portfolio D (70% Carbon Reduction; High Wind)

The Company's Portfolio D is the plan with a 70% carbon reduction and high incremental additions of new wind resources. The Company forces-in a greater amount of solar using its assumed "high solar" sensitivity parameters. Portfolio D is the same as Portfolio C, except that it reflects accelerated and incremental additions of new renewables resources to meet the 70% carbon reduction target. It includes:

1. "high" solar additions of 3,284 MW, high solar + storage additions of 2,469 MW, and same grid-tied 4-hour batteries as Portfolios A, B, and C.
2. incremental additions of new solar resources starting in 2023 and each year thereafter through 2035 resulting in cumulative incremental additions of 1,725 MW.
3. incremental additions of new solar + storage resources starting in 2029 and each year thereafter through 2035, resulting in cumulative incremental additions of 675 MW.
4. acceleration of new onshore wind resources and incremental additions in 2034 and 2035 resulting in incremental additions of 300 MW.
5. incremental additions of new Oklahoma wind resources in 2029 and each year thereafter through 2035, resulting in incremental additions of 801 MW.
6. incremental additions of new offshore wind resources in 2034 and 2035, resulting in incremental additions of 1,476 MW
7. additions of new gas-fired combustion turbine resources in 2027, 2028, and 2030, resulting in cumulative additions of 1,828 MW.
8. additions of new gas-fired combined cycle resources in 2027 and 2028 resulting in cumulative additions of 2,448 MW.

Portfolio E (70% Carbon Reduction; High SMR)

The Company's Portfolio E is the plan with a 70% carbon reduction, and it includes 684 MW of SMR Nuclear reactors in place of some of the wind energy in Portfolio D. It includes:

1. same high solar, high solar + storage, and grid-tied 4-hour batteries as in Portfolio D.
2. incremental additions of new solar resources starting in 2023 and each year thereafter through 2035 resulting in cumulative incremental additions of 1,725 MW.
3. incremental additions of new solar + storage resources starting in 2029 and each year thereafter through 2035, resulting in cumulative incremental additions of 675 MW.
4. incremental additions of new onshore wind resources in 2034 and 2035, resulting in incremental additions of 300 MW.
5. incremental additions of new Oklahoma wind resources in 2030 and each year thereafter through 2035, resulting in incremental additions of 638 MW.

6. incremental additions of new offshore wind resources in 2035, resulting in incremental additions of 138 MW.
7. incremental additions of new gas-fired combustion turbine resources in 2027, 2028, and 2030, resulting in cumulative additions of 2,742 MW.
8. additions of new gas-fired combined cycle resources in 2027, resulting in cumulative additions of 1,224 MW.

Portfolio F (No New Gas Generation)

The Company's Portfolio F is the plan that reflects no new gas-fired resources. The Company forces-in a greater amount of solar using its assumed "high solar" sensitivity parameters targets. There is a large amount of new grid-tied battery resources to provide capacity in place of the gas plants that would have otherwise been built. It includes:

1. incremental additions of new solar resources starting in 2024 and each year thereafter through 2035 resulting in cumulative incremental additions of 1,650 MW.
2. incremental additions of new solar + storage resources starting in 2029 and each year thereafter through 2035, resulting in cumulative incremental additions of 750 MW.
3. incremental additions of new onshore wind resources in 2032, and each year thereafter through 2035, resulting in incremental additions of 600 MW.
4. incremental additions of new Oklahoma wind resources in 2030, and each year thereafter through 2035, resulting in incremental additions of 638 MW.
5. incremental additions of new offshore wind resources in 2035, resulting in incremental additions of 138 MW.
6. incremental additions of new grid-tied 4-hour batteries in 2021 and each year thereafter through 2026, and 2035, resulting in cumulative incremental additions of 2,195 MW.
7. incremental additions of new grid-tied 6-hour batteries in 2035, resulting in cumulative incremental additions of 311 MW.

Conclusions – Resource Planning

The Company's six portfolios demonstrate that the Company has identified a broad range of demand-side, supply-side, storage and other technologies, as required by Act 62. The portfolios allow for consideration of different coal retirement schedules, renewables, advanced technologies, and aggressive CO_2 targets. In addition, the Company conducted a reasonable set of sensitivity analyses. The only concern, which is discussed in the Generic Resources section of this report, relates to the cost that was assumed for solar resources. The Company's assumed capital cost for solar resources is higher than was found in other sources that were considered and this may have affected the amount of solar selected economically had the cost been lower and more consistent with the other sources.

Economic Evaluation of Portfolios and Sensitivities

As discussed above in the Generic Capacity Resources section, the Company conducted a technology and economic screening process in order to develop a manageable set of potential generation alternatives. The Company screened generating technologies from both a technical perspective and an economic perspective. Once options are screened out, the remaining resources are passed on to the more detailed economic evaluation that relies on expansion plan optimization and production cost modeling.

In the detailed economic evaluation, the Company first assessed the remaining resources that it would need to satisfy its 17% winter target reserve margin criteria. When the Company constructed its production cost database, it included existing system resources and it fixed into the database all of the mandated, designated, and undesignated resources that it is or will be obligated to acquire either by statute, regulation, or for other reasons. This includes resources that were already considered committed such as the Bad Creek Pumped Storage hydro upgrade, nuclear uprates, Lincoln CT project, Clemson CHP project, and certain energy storage resources. In addition, the Company included the coal retirement dates for each portfolio being studied.

The results of the System Optimizer model provided a list of economic generating resource additions that satisfied the Company's reserve margin criteria for each of the six (6) portfolios it evaluated. Based on the list of all incremental capacity additions to its system, the Company conducted both production cost modeling analysis to develop more detailed production cost and capital revenue requirement results for each portfolio. The end result of the analysis was that the Company developed nominal dollar annual total revenue requirements and the net present value of these revenue requirements for the fifteen-year study period (2021 through 2035) and a thirty-year study period (2021 through 2050) for each Portfolio and each sensitivity of each Portfolio, a total of 54 cases.

The Company developed the annual total revenue requirements in separate Excel workbooks for each of the 54 cases.[112] Annual total revenue requirements were derived for each Portfolio and each sensitivity case, including the following components:

- production expense (fuel and variable O&M expenses),
- fixed fuel (demand) expense,
- carbon tax expense (for Portfolios B through F only) for the Company's entire system of existing and new resources,
- fixed O&M expenses,

[112] Response to ORS 2-10c, consisting of 54 confidential "PVRR" Excel workbooks with separate sheets summarizing the annual total revenue requirements and each of the costs rolling forward into the summary and the net present value of the revenue requirements for the 15-year and 30-year study periods.

- generation capital revenue requirements,
- transmission capital revenue requirements including infrastructure and interconnection costs for new resource additions.

In addition, the annual total revenue requirements include the capital and fixed operation and maintenance expense for existing coal-fired resources based on the retirement dates for the specific case modeled (either economic retirement dates or most practical retirement dates). However, the annual total revenue requirements do not include post-in-service capital expenditures and the related expenses, except for the battery resources, which include these costs in fixed O&M expenses.

The Company utilized the PROSYM production cost model to quantify the production cost expenses (variable and fixed) and CO_2 costs for the Company's system, including existing and new resources for each Portfolio and each sensitivity case. The production cost results were then loaded into the Excel PVRR workbooks.

The Company utilized an Excel workbook "capital cost" revenue requirement model and a "fixed charge rate" model to calculate unique fixed charge rates for the capital costs and capital-related expenses for each new generic resource. The "capital cost" model relied on the "fixed charge rate" model for each new generic resource included in each Portfolio.[113] The "capital cost" model calculated the annual nominal levelized capital revenue requirement cost for each generic resource. The "capital cost" model then utilized and escalated the annual nominal levelized capital costs for each new generic resource addition included in each Portfolio.[114] It also calculated the present value of the nominal dollar annual capital costs in 2020 dollars for the period 2020 through 2050.

The "fixed charge rate" model calculated a unique real levelized fixed charge rate for each new generic resource using common information, such as the cost of capital, and resource specific information, including capital (construction) cost, capital spend curve, AFUDC, inflation (escalation), book life, tax depreciation method and life, investment tax credit availability, and federal and state income rates, among others.

The Company summarized the PVRR for each Portfolio in its IRP Report in 2020 dollars from 2021 through 2050 assuming the base fuel forecast and no carbon tax, on a non-

[113] Response to ORS 2-10d, consisting of two confidential Excel workbooks, one for the "capital cost" model and the other for the "fixed charge rate" model.
[114] Response to ORS 5-5.

risk adjusted basis.[115] The least cost Portfolio, on a non-risk adjusted basis, is Portfolio A, with a PVRR of $44.4 billion, which includes transmission costs of $0.6 billion.

The highest cost Portfolio, on a non-risk adjusted basis, is Portfolio D, with a PVRR of $56.1 billion, which includes transmission costs of $4.3 billion.

Portfolio B has a PVRR of $46.8 billion, although the PVRRs for Portfolios B through F do not include the PVRR of the carbon tax itself. The Company estimates that the PVRR of the carbon tax itself ranges from $5 billion to $8 billion.

The Company also summarized the PVRR for each Portfolio fuel and carbon tax sensitivity (nine for each Portfolio) in its IRP Report, which provides a quantitative assessment of the range of PVRR results for each Portfolio by varying these key assumptions.[116]

Conclusions - Economic Evaluation of Portfolios and Sensitivities

The Company's analysis is detailed and provides reasonable quantifications of the costs for each Portfolio and each sensitivity for planning purposes based on the Portfolios and sensitivities that were studied and given the assumptions utilized to model the existing resources, especially fuel, variable operation and maintenance expenses, and purchased power expenses and operating performance existing and new resources in PROSYM; capital costs of existing coal-fired resources subject to retirement; transmission capital costs necessary if existing coal-fired resources are retired; and capital costs, fixed operating expenses, transmission infrastructure costs, and other assumptions necessary to model new generic resource additions. To the extent these assumptions are modified, then the quantifications will change and the relative differences between and among the Portfolios and the sensitivities will change.

The Company's calculation of PVRR is detailed, but includes a mixture of annual production expenses as incurred or forecast to be incurred and capital revenue requirements that have been levelized over the resources' estimated service lives, not the annual revenue requirements as they will be incurred through the regulatory process. This is appropriate for economic evaluations of potential portfolios for planning purposes, but would not be appropriate for rate impact analyses, as it would understate the near-term rate impacts of the Company's plans to transform its generation resources through retirements of existing coal-fired resources, and the longer-term rate impacts of

[115] DEC and DEP 2020 IRP, Portfolio Results table pg. 17. Combined DEC and DEP Portfolio Results table in DEC and DEP 2020 IRP, pg. 16.

[116] Table 12-B, excluding the cost of the carbon tax itself, at 96 (DEC) and 98 (DEP) of the IRP Report, and Table 12-C, including the cost of the carbon tax itself, at 97 (DEC) and 99 (DEP) of the IRP Report.

replacement of those resources with new renewables and gas-fired generation during the 15-year study period. For this reason, the Company performs separate calculations of the annual rate impacts of its portfolios, which properly address this issue and allow the Commission to balance the economic evaluation against the rate impact of the portfolios.

The Company's calculation of PVRR does not reflect the post-in-service capital expenditures and the related expenses, except for the battery resources, which include these costs in fixed O&M expenses. At page 172 of the DEC IRP Report, the Company states that in some cases, battery storage resources were determined to be less economic than CT assets. The Company did include capital addition costs for battery storage resources in the form of battery cell replenishment (augmentation) costs. Leaving out CT capital addition costs would understate the CT costs and should be investigated further.

Recommendations - Economic Evaluation of Portfolios and Sensitivities

21. ORS recommends the Company include post in-service capital costs for new resource additions in its capital cost model and its Present Value of Revenue Requirement ("PVRR") calculations for each Portfolio and each sensitivity of each Portfolio. We recommend this be addressed in a modified IRP in this proceeding. **(N)**

Risk Analysis

Each of the Portfolios and sensitivities reflect a range of risks due to an unknown and uncertain future over the study period. The Company analyzed nine sensitivities for each of the six Portfolios, for a total of 54 cases.

In Appendix A the Company compared each Portfolio on a PVRR basis across three carbon price scenarios (zero, base, and high cases), and three natural gas forecasts (low, base, and high cases), for a total of nine sensitivities.[117]

To assess the relative risk, ORS performed a Minimax Regret Analysis and an analysis of the variability within each portfolio using each Company's PVRR results.[118] The results are shown in Table 18. The values in the DEC Portfolio Regret Tables below represent the PVRR amount by which each Portfolio exceeds the lowest cost Portfolio in each fuel cost and CO2 price case.

[117] DEC 2020 IRP, Appendix A, pg. 189.

[118] A regret analysis quantifies the amount by which a given portfolio exceeds the least-cost portfolio. It is a means to understand the risks associated with each portfolio given the uncertainty in future fuel and carbon prices. A portfolio with a small amount of regret across a variety of pricing scenarios is robust to a variety of futures.

TABLE 18

Minimax Regret Analysis	Base Plan without Carbon Policy	Base Plan with Carbon Policy	Earliest Practicable Coal Retirements	70% CO_2 Reduction: High Wind	70% CO_2 Reduction: High SMR	No New Gas Generation
High CO_2-High Fuel	$2.10	$0.20	$0.00	$4.50	$1.60	$4.60
High CO_2-Base Fuel	$1.50	$0.20	$0.00	$5.90	$3.00	$5.70
High CO_2-Low Fuel	$1.10	$0.20	$0.00	$6.60	$3.70	$6.40
Base CO_2-High Fuel	$1.40	$0.00	$0.10	$5.60	$2.70	$5.50
Base CO_2-Base Fuel	$0.90	$0.10	$0.00	$6.90	$4.00	$6.60
Base CO_2-Low Fuel	$0.50	$0.00	$0.00	$7.70	$4.80	$7.30
No CO_2-High Fuel	$0.00	$0.10	$1.90	$10.20	$7.30	$9.00
No CO_2-Base Fuel	$0.00	$0.50	$1.40	$11.10	$8.20	$10.20
NO CO_2-Low Fuel	$0.00	$0.80	$1.30	$11.90	$8.90	$10.90

The values in Table 19 below compare the variability within each portfolio, e.g., the amount each portfolio's PVRR changes from scenario to scenario. From a pure variability perspective, the highly renewable options are the best performing. Although the high renewable cases are not as susceptible to variability in natural gas prices and perform well under carbon constrained cases, their higher capital costs outweigh the potential savings. In the end, the low variability cases result in higher prices being locked in.

The Base with Carbon Pricing Portfolio has the lowest maximum regret result. It also has the lowest regret variability.

TABLE 19

Minimax Regret Analysis	Base Planning without Carbon Policy	Base Planning with Carbon Policy	Earliest Practicable Coal Retirements	70% CO_2 Reduction: High Wind	70% CO_2 Reduction: High SMR	No New Gas Generation
Max Regret	$2.10	$0.80	$1.90	$11.90	$8.90	$10.90
Mean Regret	$0.83	$0.23	$0.52	$7.82	$4.91	$7.36
Regret Standard Deviation	$0.76	$0.26	$0.78	$2.62	$2.60	$2.20

These results suggest that if higher natural gas and CO_2 prices were modeled in the different scenarios, the outcome would be that the renewable heavy portfolios perform comparatively better.

Customer Rate Impacts

In addition to the calculations of PVRR for planning purposes, the Company calculated the average retail and residential rate (bill) impacts on an annual nominal dollar basis and presented the cumulative rate impacts in 2030 and 2035 in its IRP Report.[119] It calculated the annual revenue requirement for each Portfolio using the incremental investment and incremental expenses for each portfolio and then added the incremental revenue requirement to the present average retail and residential rates.[120] It also calculated an average annual compound growth rate in average retail and residential rates through 2030 and 2035 and presented these results in its IRP Report.

The result is not a forecast of average retail and residential rates in those years because the calculations do not include the effects of changes in other costs in the generation and other functional areas of operations or in administrative and general expenses. Rather, the calculations are best used to quantify and compare the rate differentials among the various Portfolios in those years and to assess those differentials as a percentage of present rates.

The customer rate impacts are significant factors for the Commission to consider when evaluating each Portfolio and the potential pathways represented by each Portfolio. Not surprisingly, the lowest customer rate impact is Portfolio A. The greatest customer rate impacts are Portfolios D through F, which also are the most uncertain due to the unknown future carbon reduction targets, maturity and availability of technologies, costs of various technologies, and infrastructure required, among other factors.

The following figures show the annual and cumulative percentage increases in the average retail rates for each Portfolio, the first two with the cost of a carbon tax included in the revenue requirement (for Portfolios A through F) and the last two without the cost of a carbon tax included (for Portfolios B through F). The cumulative percentage increases on the average retail rates are significant, especially for Portfolios D through F, which are the high wind, SMR, and no new gas generation cases.

Begin Confidential Figures

[119] DEC 2020 IRP p. 191-192, including Table A-17.
[120] Response to ORS AIR 2-30, which includes an Excel workbook with the assumptions, data, and calculations.

Figure 12

[redacted]

Figure 13

[redacted]

Figure 14

[redacted]

Figure 15

[redacted]

End Confidential Figures

The following are observations we made when these analyses were performed. First, there are differences in the Company's calculations of the average retail rate effects and the Company's calculations of the PVRR for economic evaluation purposes. The first difference is that for its rate impact analysis, the Company calculated capital revenue requirements based on a ratemaking approach, which reflects the cost of the new resources on a declining cost basis as the installed cost is depreciated over its service life and accumulated deferred income taxes increase in the early years of its service life. However, for purposes of economic analyses, the Company calculated the capital revenue requirements on a levelized cost basis. These differences are normal modeling approaches that are typically used, and simply reflect the different purposes that each of the calculations are used for.

The second difference is that the Company calculated the average retail rate impact using the most recent capital structure and costs of capital authorized by the South Carolina and North Carolina Commissions,[121] but calculated the PVRR using a generic capital structure, generic cost of common equity, and an assumption regarding the incremental cost of debt.[122] The differences in the capital structure and costs of capital between the two calculations are confidential. The Company's calculation of the average retail rate impact is conceptually incorrect and should reflect the same assumptions as it used for the capital structure and cost of capital in the calculations of the PVRR. Only the incremental cost of capital applied to the rate base cost of the new resources, transmission, and other capital costs is recoverable in incremental rates. It is unlikely that correcting this error will materially change the average retail rate impact of the Portfolios, at least on a relative basis.

The third difference is that the Company calculated the average retail rate impact with depreciation expense using authorized depreciation rates for its existing resources rather than the depreciation rates for the new resources calculated in the PVRR as one (1) divided by the service life. The Company's calculation of the average retail rate impact is conceptually incorrect and should reflect the same assumptions it used for the depreciation expense in the PVRR. The Company's authorized depreciation rates do not reflect the service lives of new resources, but rather the remaining net book value and net salvage value that still must be recovered over the remaining lives of its existing resources. It is unlikely that correcting this error will materially change the average retail rate impact of the Portfolios, at least on a relative basis.

There are additional differences in other assumptions and methodologies, for example, in the combined federal and state income tax rates. These assumptions also should be

[121] Response to ORS AIR 2-10D-2 ((DEC) CONFIDENTIAL tab labeled "Common").
[122] Response to ORS AIR 2-30 DEC Cost of Service and Rate Impact (tab labeled "DEC-SC-COS.")

consistent between the calculations of the average retail rate impact and the PVRR. Like the other errors, it is unlikely that correcting this error will materially change the average retail rate impact of the Portfolios, at least on a relative basis.

Finally, as noted in the Economic Evaluation of Portfolios and Sensitivities section of the Report, the Company's calculation of PVRR does not reflect the post-in-service capital expenditures and the related expenses, except for the battery resources, which include these costs in fixed O&M expenses. In addition to the PVRR, this understates the customer rate impacts of the Portfolios and sensitivities. However, it is unlikely that including these costs will materially affect the customer rate impacts of the Portfolios and sensitivities, at least on a relative basis.

Conclusions – Customer Rate Impacts

The average retail rate impact provides the Commission important information regarding the real-world impact of both the timing and magnitude of rate increases resulting from each of the Portfolios. For example, Portfolio A will result in a cumulative increase in the average retail customer rates of [redacted]% over the next 15 years. Portfolio A assumes there is no CO_2 tax. In contrast, Portfolio F will result in a cumulative increase in the average retail customer rates of [redacted]% over the next 15 years, assuming that there is a CO_2 tax and the cost of the CO_2 tax is included.

The Company's calculations of the average retail rate impact reflect the conceptual errors identified above. The calculations should use assumptions and methodologies that are consistent with the assumptions and methodologies used in the calculations of the PVRR, except for the levelization of the capital-related costs. However, the correction of these errors will not affect the ranking of the Portfolios on a PVRR basis; rather, it affects only the calculation of the potential average retail rate impact of the Portfolios, an important factor to consider, but not the primary factor. Further, it is unlikely that correcting the error will materially change the average retail rate impact of the Portfolios, at least on a relative basis.

Finally, the Company's calculations of the customer rate impacts are understated because they do not include the effects of post-in service capital expenditures and the related expenses. However, it is unlikely that including these costs will materially affect the customer rate impacts of the Portfolios and sensitivities, at least on a relative basis.

Recommendations – Customer Rate Impacts

22. The average retail rate impacts are an important consideration when assessing whether Portfolios and the pathways reflected in those Portfolios are reasonable.

This should be considered in this IRP and future IRPs, but it does not require a modified IRP in this proceeding. **(N)**

23. ORS recommends the Company revise the calculation of the average retail rate impact on customers so that the assumptions and methodologies are consistent with the calculations of the PVRR, except for the levelization of the capital-related costs. We recommend this be included in a modified IRP in this proceeding. **(N)**

Transmission System Planning and Investment

The Company provided a summary of its transmission planning process in Chapter 7 and Appendix L of the IRP report. The Company indicated, "There are presently no new lines, 161 kilovolt ("kV") and above, currently planned for construction in DEC's service area,"[123] but it explained that significant transmission investments will be required in the future as it retires existing coal units and integrates new resources to its system. The Company included estimates of transmission costs with each portfolio, though the costs were developed as high-level estimates. The Company notes that extensive studies will be required to analyze the complex interactions of new resources on its system so that it can determine better transmission cost estimates.[124] For example, the Company developed its cost estimates assuming that replacement units would be developed at greenfield sites and it did not consider the savings that might be achieved by replacing resources on the same site.[125]

The Company developed transmission upgrades cost estimates based on three portfolios:[126]

- Base with Carbon Policy – $560 million.
- 70% CO_2 Reduction: High Wind Portfolio - $1.7 billion, including the cost of a new line to transport offshore wind power to its system.
- No New Natural Gas Portfolio would require - $1.9 billion.

Estimates of transmission costs that were used in the other three portfolios were derived by scaling costs from components in the above three forecasts. It is important to note that because transmission cost estimates were added to each portfolio in this way, the Company did not include transmission costs associated with each generation resource

[123] DEC 2020 IRP, pg. 376.
[124] *Id.* pg. 53.
[125] *Id.* pg. 56 and 57.
[126] *Id.* pg. 57. Additional confidential details may be found in NCPS DR 3-17.

option in the capacity expansion model (System Optimizer).[127] In addition, estimates of transmission costs required to retire DEC coal resources that were used are:

- Marshall Units 1 – 4 - $200 million.
- Belews Creek Units 1&2 - $230 million.
- Cliffside Units 5&6 – Cliffside Unit 5 does not require transmission upgrade to retire, and Cliffside Unit 6 is assumed to operate on natural gas and therefore was not a retirement candidate.
- Allen Units – Transmission projects to enable retirements are underway; however, the costs of these projects are not modeled or included in the IRP.[128]

The Company also conducted a high level assessment of the transmission related costs associated with increasing the import capability between DEC/DEP and neighboring utilities by 5,000 to 10,000 MWs. DEC and DEP cost estimates for these transmission projects are:

- 5 GW import capability: $4-5 Billion
- 10 GW import capability: $8-10 Billion

The Company conducts detailed annual transmission studies that evaluates changes in load, generating capacity, transactions, and topography to maintain system reliability. In addition, the Company undergoes South Eastern Reliability Corporation ("SERC") audits every 3 years to ensure compliance with NERC standards.

Distribution Resource and Integrated System Operations Plans

Section 40(B)(2) contains the provision that "An integrated resource plan may include distribution resource plans or integrated system operations plans." The IRP report complies with this optional requirement and describes distribution resource plans most significantly in Chapter 15, where it discusses plans for ISOP. It also discusses Integrated Volt-Var Control (ICCV) in Appendix D.

<u>ISOP</u>

The Company believes this effort will be important "to address the trends in technology development, declining cost projections for energy storage and renewable resources, and customer adoption of electric demand modifying resources such as roof-top solar and

[127] NCPS DR 3-18.
[128] DEC IRP Repty pg. 57.

EVs."[129]

According to the Company, more advanced distribution planning will allow it to better analyze the distribution and transmission systems to account for increasing variability of generation and two-way power flows on an increasingly distributed system. The Company notes that it will have to upgrade its modeling data and tools. This process is underway and ISOP planning will be introduced in the 2022 IRP. The analyses conducted will involve developing circuit level forecasts on an hourly time scale. The Company is currently developing these forecasts to use in its Advanced Distribution Planning ("ADP") Toolset. Duke Energy is working with CYME, who it notes is an industry leader in distribution modeling to develop its ADP tool.

The Company asserts that its ISOP efforts will ultimately enable wider adoption of distributed resources based on these considerations:[130]

> The new functionality of the ADP toolset will enable planners to evaluate [Distributed Energy Resources] (including energy storage) as a potential solution for capacity needs and identify the most likely hourly patterns where potential new DERs would be needed to address local issues…
>
> ……the Company has also worked on developing screening processes to efficiently identify distribution upgrade needs that could potentially be deferred with non-traditional solutions.

These tools should allow the Company to evaluate resource options such as energy storage more quickly than it is currently able to do. ISOP will also allow for greater integration of the Company's distribution and transmission planning processes, which the Company asserts will allow future transmission and distribution plans to be conducted "from a more holistic perspective."[131]

IVVC

In its IRP Report, the Company introduced its newly developed Integrated Volt-Var Control ("IVVC") program, which has the objective of reducing winter peak demand and lowering overall energy consumption on its system, and involves the coordinated control of distribution equipment in substations and on distribution lines to optimize voltages and power factors on the distribution grid. Plans call for IVVC to "…allow the Company to more closely monitor and control the voltage on the distribution system and more

[129] DEC 2020 IRP, pg. 124.
[130] *Id*. pg. 126.
[131] DEC 2020 IRP, pg. 124.

effectively manage voltage fluctuations due to intermittency of renewable energy sources, while enabling energy and peak demand savings to our customers over time."[132]

Other Considerations

Other Considerations - Stakeholder Engagement

The company discusses its stakeholder engagement efforts throughout the IRP report and on its website.[133] The Company's engagement process appears to be extensive as it solicits and incorporates stakeholder feedback across a variety of topics. The following items were addressed as a result of its stakeholder process:

- Inclusion of the 70% CO_2 Reduction Portfolios and the No New Gas Portfolio. Stakeholders provided input on resource planning, carbon reduction, energy efficiency, and demand response.[134]
- NREL Carbon-Free Resource Integration Study[135]
- Demand Side Management and IVVC Programs[136]
- Winter Peak Shaving Study[137]
- Carbon Reductions, Financial Impacts, and Customer Reliability[138]
- Resource Adequacy Study[139]
- ISOP Development. This included releasing a ISOP Stakeholder Engagement Report to document the process and key takeaways[140]

The Company appears to have gathered, documented, and incorporated stakeholder feedback into the IRP process across a breadth of subjects. However, ORS notes that it has presented several recommendations in this Report to be addressed in a future IRP and looks forward to addressing those issues with the Company and other parties in its stakeholder engagement process.

[132] *Id.* pg. 134.
[133] https://www.duke-energy.com/our-company/sustainability/stakeholder-engagement
[134] DEC 2020 IRP p. 10, 22.
[135] *Id.* pg. 6.
[136] *Id.* pg. 12.
[137] *Id.* pg. 12.
[138] *Id.* pg. 18.
[139] *Id.* pg. 63.
[140] *Id.* pg. 129 and & https://www.duke-energy.com/_/media/pdfs/our-company/isop/icf-duke-isop-stakeholder-engagement-report.pdf?la=en

Other Considerations - Action Plan

Although the statutory requirements of Section 40 do not mandate that a utility include a short-term action plan, it is typical that most utility IRP Reports do include such a plan. DEC provides a chapter, Chapter 14 that discusses its short-term action plan. Table 14-B[141] in the IRP Report (reproduced in Exhibit 1 below), provides a graphical summary listing the resource actions that may be addressed between 2021 and 2025. Those resources are categorized into retirements, additions, solar, solar with storage, biomass/hydro, cumulative EE, DSM, and IVVC. The information in Table 14-B is associated with the Base Case with Carbon Portfolio. Additional information regarding the other portfolios may be found in NCPS DR 7-1.

In addition to providing the short-term action plan for the 2020 IRP, Exhibit 1 below also compares the Company's 2020 IRP Report short-term action plan to its 2019 short-term action plan. The biggest changes between the two are accelerated coal unit retirements and a slower buildup of solar generation.

The Company's short-term action plan provides useful information for evaluating the resources the Company is likely to pursue over the next five years. One area in which the Company should improve the short-term action plan is to provide additional clarity about the status of resources that are included in the action plan. For example, in Table 14-B, the Company identifies coal retirements, the Lincoln CT project, unnamed energy storage projects, nuclear uprates, Bad Creek upgrades, and unnamed CHP projects. Because those projects fall within the action plan time horizon they warrant additional specific details about the actions the Company is taking or will soon take regarding those resources.

For each of these categories of resources there is certain information that would be helpful to have located specifically in the action plan section. For retirements occurring within the five-year action plan window, it would be useful if the Company would provide information explaining the regulatory process and other significant hurdles that the Company will have to go through to actually retire those units. Based on the IRP, it would appear that the Company is proposing to retire Allen Units 2-4 as soon as the end of this year, yet it is not clear what steps the Company is taking or will have to take to formally retire those units. With regard to the Lincoln CT project, the Company will be acquiring that unit during the action plan horizon, and it would be useful if the Company would provide when the commitment for the project occurred and the docket it was approved in. For the unnamed CHP resources and energy storage projects, since those are within the action plan horizon, it would be useful if the Company could identify the specific steps it

[141] DEC 2020 IRP, pg. 120.

will take to acquire those specific resources. For the nuclear uprates and Bad Creek upgrades, it would be useful if the Company could provide an update explaining the status of those project.

Other Considerations - Southeast Energy Exchange Market ("SEEM")

On December 11, 2020, the Company filed with the North Carolina Utilities Commission information regarding the proposed SEEM platform agreement[142]. The Company stated that the SEEM will establish "a region-wide, automated, intra-hour platform to match buyers and sellers with the goal of more efficient bilateral trading and assumes utilization of unused transmission capacity to achieve cost savings for customers in the Southeast region of the country ("Platform")." The automated system will allow buyers and sellers to enter into trades on a 15-minute basis utilizing transmission capacity that otherwise would be unused.

To be clear, the SEEM will not be a new Regional Transmission Organization ("RTO") for the southeast similar to PJM or MISO, nor will it be an energy imbalance market similar to the Energy Imbalance Market ("EIM") that PacifiCorp and the California Independent System Operator launched in 2014, referred to as the Western EIM. The SEEM will allow participants to be able to trade with other members on a sub-hourly basis (every 15-minute basis) and do so using a platform that has been set up to automate the transaction process. In comparison, the Western EIM also allows participants to transact on a sub-hourly basis, however, the Western EIM is a real-time system that provides economically optimized dispatch instructions to participating members' generating units and derives payments based on locational marginal prices.

One important distinction is that the Western EIM sends dispatch signals to generating units, whereas the SEEM will only automate the process of allowing two parties to enter into a transaction, however, it will allow for transactions to take place on a 15 minute basis. The purpose of this discussion is to provide a brief description of the differences between the plans for the SEEM and the way an EIM operates.

In addition, DEC should incorporate details regarding the SEEM in the future IRP. ORS notes that PacifiCorp routinely provides information in its IRP to inform stakeholders about

[142] NCUC dockets: Docket Nos. E-7, Sub 1245 and E-2, Sub 1268; December 11, 2020 filing: https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=ee53f541-e7e5-41c2-b000-e32e5660873f

its involvement in the Western EIM, and to identify the benefits of its participation on an ongoing basis[143].

ORS recommends that in future IRPs, the Company should provide details regarding the status of the SEEM, details regarding important current and planned activities, and information regarding the monetary benefits that have been achieved by implementation of the SEEM.

Recommendations – Other Considerations – Action Plan

24. ORS recommends the Company provide additional details and status updates about resources included in the action plan, including coal retirements, the Lincoln CT project, unnamed energy storage projects, nuclear uprates, Bad Creek upgrades, and unnamed CHP projects. We recommend this information be included in a modified IRP in this proceeding. **(N)**

Recommendations – Other Considerations – SEEM

25. ORS recommends that in future IRPs, the Company provide details regarding the status of the SEEM, details regarding important current and planned activities, and information regarding the monetary benefits that have been or could be achieved by implementation of the SEEM. We recommend this be addressed in the future through the Company's stakeholder process. **(L)**

[143] Pacificorp 2019 IRP, pg. 2; https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_I.pdf

Exhibit 1

2019 DEC IRP Action Plan

Year	Retire (MW)		Additions (MW)		Solar (MW)	Solar with Storage (MW) Solar	Storage	Biomass/ Hydro (MW)	EE (MW)	DSM (MW)	IVVC (MW)
2019											
2020			Clem CHP	15	1137	0	0	97	61	469	0
2020			Eng Storage	5							
2021			Eng Storage	20	1407	75	13	83	115	468	0
2021			Bad Crk Up	65							
2021											
2021											
2022			Eng Storage	25	1738	135	30	61	167	468	0
2022			Bad Crk Up	65							
2022			Nucl Uprate	15							
2022											
2023			Eng Storage	25	2011	155	35	61	220	468	0
2023			Bad Crk Up	65							
2023			Nucl Uprate	15							
2023											
2024			Eng Storage	25	2332	196	46	57	297	469	0
2024			Bad Crk Up	65							
2024			Nucl Uprate	15							
2025	Allen 1-3	604	Lincoln CT	402							
2025											
2026											
2027											
2028											
2029	Allen 4-5	526									
2030											
2031	Lee 3	173									
2032											
2033	Cliff 5, Q Creek	547									
2034											
2035	Marshall 1-4										
2036											
2037											
2038											
2039	Belews 1,2										
2040											
2041											
2042											
2043											
2044											
2045											
2046											
2047											
2048											
2049	Cliffside 6										

2020 DEC IRP Action Plan

Year	Retire (MW)		Additions (MW)		Solar (MW)	Solar with Storage (MW) Solar	Storage	Biomass /Hydro (MW)	EE (MW)	DSM (MW)	IVVC (MW)
2019											
2020											
2020											
2021			Clem CHP	16	966	0	0	132	70	478	0
2021			Eng Storage	9							
2021			Bad Crk Up	65							
2021			Nucl Uprate	6							
2022	Allen 2-4	704	Eng Storage	20	1327	115	25	118	129	467	0
2022			Bad Crk Up	65							
2022			Nucl Uprate	21							
2022			CHP	30							
2023			Eng Storage	25	1673	134	30	81	183	468	17
2023			Bad Crk Up	65							
2023			Nucl Uprate	30							
2023			CHP	30							
2024	Allen 1, 5	426	Eng Storage	25	1976	163	37	81	233	470	34
2024			Bad Crk Up	65							
2024											
2025			Eng Storage	25	2268	192	45	59	303	473	173
2025			Lincoln CT	402							
2026	Cliffside 5	546									
2027											
2028											
2029											
2030											
2031	Lee 3	173									
2032											
2033											
2034											
2035	Marshall 1-4	2078									
2036											
2037											
2038											
2039	Belews Ck 1-2										
2040											
2041											
2042											
2043											
2044											
2045											
2046											
2047											
2048											
2049	Cliffside 6										

Review of Duke Energy Progress, LLC 2020 Integrated Resource Plan Docket No. 2019-225-E

South Carolina
Office of Regulatory Staff

February 5, 2021

Review of Duke Energy Progress, LLC
2020 Integrated Resource Plan

Pursuant to Section 58-37-40, South Carolina Code of Laws

February 5, 2021

Prepared for the South Carolina Office of Regulatory Staff
by
J. Kennedy and Associates, Inc.

Table of Contents

Executive Summary

The South Carolina Office of Regulatory Staff ("ORS") provides this Report to summarize its review of Duke Energy Progress, LLC's ("DEP" or "Company") 2020 Integrated Resource Plan ("IRP") filed September 1, 2020, in Docket No. 2019-225-E. In this report, when discussed collectively, DEP and its affiliated utility, Duke Energy Carolinas, LLC ("DEC"), will be referred to as "Duke Energy."

ORS, with the assistance of J. Kennedy and Associates, Inc. ("JKA"), evaluated DEP's IRP to determine if DEP complied with the statutory requirements of S.C. Code Ann. §58-37-40 ("Section 40"), as amended by the South Carolina Energy Freedom Act ("Act 62"), and the requirements of the Public Service Commission of South Carolina's ("Commission") Order No. 98-502.

Act 62 was signed into law by Governor McMaster on May 16, 2019. Act 62 amended and expanded the prior Section 40 IRP requirements. Act 62 includes a list of specific information that each utility must provide in its IRP, requires that the Commission determine whether the utility's IRP represents the "most reasonable and prudent means of meeting the electrical utility's energy and capacity needs as of the time the plan is reviewed,"[1] and sets forth seven factors for the Commission to consider in its determination of whether to approve, require modifications, or reject the utility's resource plan, among other procedural and substantive requirements.

Act 62 also states that any resource plan accepted by the Commission "shall not be determinative of the reasonableness or prudence of the acquisition or construction of any resource or the making of any expenditure."[2] Act 62 further states that the utility retains the burden to prove in a future cost recovery proceeding that any investment and expenditure it makes is reasonable and prudent.[3]

DEP is an electric utility that provides electric retail service to 1.6 million customers located in a 29,000-square-mile service area in northeastern South Carolina and sections of Piedmont, Coastal, and Western North Carolina.[4] DEP had 2019 summer and winter peak loads of 12,953 and 13,715 megawatts ("MW")[5] respectively, and an installed capacity base of about 13,700 MW of DEP-owned resources.[6]

DEP's IRP is the same for South Carolina and North Carolina due to the fact that it operates as a single system without consideration of the geographic boundaries of the

[1] S.C. Code Ann. § 58-37-40(C)(2).
[2] S.C. Code Ann. § 58-37-40(C)(4).
[3] *Id.*
[4] DEP 2020 IRP Report, filed September 1, 2020, pgs. 4 and 25.
[5] *Id.* pgs. 227 and 228.
[6] *Id.* pg. 4.

two states. DEP did not develop a separate IRP for each state. Although DEP's IRP was developed on a standalone basis (not consolidated with DEC), it addresses the fact that DEP and DEC operate under a combined dispatch, which provides certain reliability and cost benefits for planning purposes. The Company states, "[i]t is important to note that DEP and DEC cannot develop different IRPs for each system [in each state]. Accordingly, it is in all parties' interest that the resulting IRPs accepted or approved in each state are consistent with one another."[7] Nevertheless, there are different statutory and regulatory requirements in each state that affect the Company's IRP, including the selection and magnitude of demand side management ("DSM") and energy efficiency ("EE") programs, selection of new generation resources, portfolios considered, and costs of each portfolio, among other issues. For example, a significant portion of the new renewable resources in the IRP are "forced in" (not economically added) to comply with North Carolina, not South Carolina, statutory and other regulatory requirements.

While the Company's IRP was developed without differentiation by state, when making cost allocations, the Commission has the authority to differentiate and directly assign or allocate the costs of certain resources for ratemaking purposes. Such direct assignments or allocations typically are addressed in ratemaking proceedings, not IRP proceedings, although the issues can be identified in the IRP proceedings.

This is the first DEP IRP to address the Act 62 requirements concerning a comprehensive IRP. Act 62 requires that a utility file a comprehensive IRP every three years and an updated IRP in the intervening two years.[8] The Company states that the objectives of an IRP are to "balance the need for system reliability, consumer affordability and increasingly clean energy supply,"[9] and it also states a utility does this by providing stakeholders, "projections or forecasts of how the utility's supply-side and demand-side resources could change over a 15-year planning horizon."[10]

The DEP IRP provides a series of six resource Portfolios, which it refers to as "potential pathways for how the Company's resource portfolio may evolve over the 15-year period (2021 through 2035) based on current data and assumptions across a variety of scenarios."[11] The first plan that the Company developed, "Portfolio A," reflects current federal and state environmental policies (also referred to as the "Base Case without CO_2" plan). Portfolio B is similar to Portfolio A, but it assumes that a form of federal carbon policy will be implemented (also referred to as the "Base Case with CO_2" plan).

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[7] Direct Testimony of Glen Snider, pg. 9, ln.16.
[8] Duke Energy notes that its historical practice has been to file a comprehensive IRP every two, and it appears that Duke Energy would prefer to maintain that schedule to be consistent with North Carolina IRP requirements.
[9] Direct Testimony of Glen Snider, pg. 8, ln. 4.
[10] *Id.* pg. 7, ln. 22.
[11] DEP 2020 IRP, pg. 5.

The Company developed four additional Portfolios that would achieve greater levels of CO_2 reductions compared to Portfolio B based on earlier retirements of existing coal resources and different selections and additions of new renewable, natural gas-fired, storage, and advanced nuclear resources.

The Company's parent company, Duke Energy, Inc., has established a corporate-wide CO_2 reduction goal that is more stringent than present statutory and regulatory requirements at the federal and state levels. The parent company's corporate CO_2 reduction goal is an important theme discussed throughout its IRP Report and is the driving factor in the retirement of existing resources and selection and addition of new resources in four of the six Portfolios, Portfolios C through F. Duke Energy, Inc.'s corporate-wide goal is to reduce CO_2 emissions at least 50% from 2005 levels by 2030 and to achieve net-zero CO_2 emissions by 2050.[12] The Company states that all six of the Portfolios could achieve the Duke Energy, Inc. corporate-wide goal CO_2 reduction goal through the phased retirement of all its existing coal-fired generating units and new renewable resource additions. However, the Company acknowledges that it will have to protect customer rates and ensure the reliability of its utility systems. In the IRP, DEP evaluated two different coal retirement schedules. One schedule reflects coal retirements based on an economic retirement study performed as part of the IRP. That coal retirement schedule is reflected in Portfolios A, B, and F. The other schedule accelerates coal retirements based on the earliest practicable schedule that can be achieved while preserving the safety and reliability of the system, but it does so without considering the economics of the accelerated coal retirements compared to replacement resources. That schedule is reflected in Portfolios C, D and E.

The Company states that there is no immediate need for decisions to acquire or build new resources in this IRP. However, the Company planned to retire the natural gas-fired Darlington Combustion Turbine (CT")1-4, 6-8, and 10 units by March 31, 2020. Thus, those decisions are near-term even if there is no immediate need to replace those existing resources with new resources.

DEP has provided the specific information required by Section B(1) of Act 62. This information is necessary for the Commission to assess the Company's IRP, consider the seven factors set forth in Section C(2) of Act 62, and determine whether the utility's IRP represents the "most reasonable and prudent means of meeting the electrical utility's energy and capacity needs as of the time the plan is reviewed." However, ORS has identified some areas for improvement and provides recommendations that address the IRP process, load and energy forecasts, generic resource profiles, production cost and revenue requirements modeling, and assumptions relied on to develop the

[12] https://news.duke-energy.com/releases/duke-energy-aims-to-achieve-net-zero-carbon-emissions-by-2050

portfolios and the resulting comparative metrics, including customer rate impacts. Some of the recommendations address issues that could be addressed in the form of a modified IRP in this proceeding. These are designated with an "N" to recommend the Company act now to modify the IRP. The others address recommendations that could be addressed in the next annual update IRP later this year (designated with an "L"), but no later than the next comprehensive IRP in 2023. The later recommendations are no less important, but we recognize that the implementation of these could require more time and could benefit from guidance achieved through the stakeholder process.

Load and Energy Forecasts

1. ORS recommends the Company provide a technical appendix that more fully describes each of the models, presents the statistical results and shows the individual energy and peak load forecast results that were actually developed. While DEP's IRP provides an overview of this information, it does not provide the detail necessary to fully evaluate the entire forecast. This detail was provided in response to discovery in this proceeding, however, we recommend this level of detail be included in future IRPs as part of a comprehensive technical appendix. **(L)**

Resource Adequacy – Reserve Margin Issues

2. ORS recommends the Company provide a more detailed discussion of the specific methodology used to develop the synthetic loads for extreme low temperature periods. While the Resource Adequacy Report provides an overview of this issue, it does not provide sufficient detail regarding how the analysis was conducted or what specific additional adjustments were made to the load data at extreme low temperatures. This detail was provided in response to discovery in this proceeding, however, we recommend this level of detail be included in future IRPs as part of a comprehensive technical appendix. **(L)**

3. ORS recommends the Company further develop its methodology to model the effects of extreme low temperatures on winter peak load. Given the significance of this issue, as discussed in the ORS Report, there may be alternative methodologies that the Company could consider to develop its synthetic loads in hours in which the temperatures fall significantly below the temperatures experienced during the weather/load estimation period (i.e., neural net model training period). We recommend this be addressed in future IRPs through the Company's stakeholder process. **(L)**

4. ORS recommends the Company provide a detailed discussion in the IRP Report or appendices that explains how the results of the Astrapé Consulting ("Astrapé") 2018 Solar Capacity Value Study were used to derive the assumed winter peak

standalone solar photovoltaic ("solar") capacity value of 1%. We recommend this information be included in a modified IRP in this proceeding. **(N)**

Energy Efficiency and Demand Side Management

5. ORS recommends the Company provide additional justification for selecting the Base EE/DSM case as opposed to the High EE/DSM case for use in Portfolio A, given that the High EE/DSM case may provide greater customer benefits. We recommend this information be included in a modified IRP in this proceeding. **(N)**

6. ORS recommends that, in addition to the sensitivity cases included in Table A-9, the Company also evaluate high and low levels of EE/DSM using high fuel/CO_2 and low fuel/CO_2 assumptions. We recommend this information be included in a modified IRP in this proceeding. **(N)**

7. The Company provided no basis for the low EE/DSM forecast that it used in the IRP. The Company's approach may be reasonable; however, it would be a better practice to provide more justification as to how it derived the low EE/DSM forecast. ORS recommends the Company provide additional justification or consider other approaches for deriving the low EE/DSM forecast. We recommend this be addressed in future IRPs through the Company's stakeholder process. **(L)**

Natural Gas Price Forecasts

8. ORS recommends the Company review its natural gas price forecasting methodology and investigate alternative approaches. We recommend this be addressed in future IRPs through the Company's stakeholder process. **(L)**

CO_2 and Other Environmental Issues

9. ORS recommends the Company provide tables summarizing the capital and operations and maintenance ("O&M") costs for compliance with environmental regulations by unit and by environmental regulation, and include descriptions explaining those costs. We recommend this information be included in a modified IRP in this proceeding. **(N)**

Existing System Resources

10. To ensure there are no inconsistencies in modeling data, we recommend the Company create a cross reference table that compares each resource modeled in PROSYM, including generating units, demand response, purchase contracts, sales contracts, EE, etc. to the corresponding data in the Load, Capacity and Reserves ("LCR") table, on a resource by resource basis. We recommend this be developed for both the Base Case with CO_2 and Base Case without CO_2 cases,

and cover all of the years in the study period. We recommend this information be provided in a modified IRP in this proceeding. **(N)**

11. Recognizing that the Oconee units' licenses will not expire for about fifteen (15) years, that the Robinson 2 unit will expire in 2030, and that it only takes five (5) years to relicense units, we recommend the Company supply additional information regarding its relicensing plans (including a timeline) and its plans to conduct economic evaluations to assess the benefits of relicensing the units. We recommend the Company provide additional insight into why it is beginning this process so far in advance of the relicensing dates, and why Robinson 2 is relicensing after Oconee. We recommend this information be provided in a modified IRP in this proceeding. **(N)**

12. Reserved

13. ORS recommends DEP provide additional clarification regarding its plans for the retirement of the Darlington CT units, including details about any transmission impacts. We recommend this information be provided in a modified IRP in this proceeding. **(N)**

14. ORS recommends the Company provide evidence that the optimal retirement dates that were determined with the Sequential Peaker Method ("SPM") are comparable to the optimal retirement dates the System Optimizer model would produce if it were used in the retirement study. We recommend this information be provided in a modified IRP in this proceeding. **(N)**

Generic Resource Options

15. ORS recommends the Company supply additional information explaining the basis for how combined heat and power units ("CHP") resources were added to the short-term action plan and explain why CHP resources were not treated as selectable resources in the economic optimization process, if in fact they were not. We recommend this information be provided in a modified IRP in this proceeding. **(N)**

16. ORS recommends DEP provide additional justification for its CT capital cost assumption. We recommend this information be provided in a modified IRP in this proceeding. **(N)**

17. ORS recommends DEP provide additional justification for its Battery Energy Storage fixed O&M cost and capacity factor assumptions. We recommend this information be provided in a modified IRP in this proceeding. **(N)**

18. ORS recommends the Company include an additional solar generic resource option in its IRP modeling assumptions that reflects the kind of solar purchase power agreements ("PPA") prices that may be available in the market. As a proxy, the Company could assume $38/ megawatt-hour ("MWh") as the solar PPA cost. We recommend this be addressed in a modified IRP in this proceeding. **(N)**

19. Given the importance that solar capacity values and solar plus battery energy storage capacity values potentially could have on the IRP analysis, ORS recommends that further investigation be conducted regarding these values with stakeholder input, discussed as part of a stakeholder engagement process. One investigation that could be performed would be to assess the impact on the Company's base case resource plan if higher winter capacity value ratings were assumed such as 5% for solar and 30% for solar plus battery energy storage. We recommend this be addressed in the future through the Company's stakeholder process. **(L)**

<u>Renewables</u>

20. ORS recommends the Company provide a table identifying each renewable resource option that was modeled, and include whether the resource was forced-in or economically selected (System Optimizer or other approach), the reason the resource was forced-in (e.g. Competitive Procurement of Renewable Energy Program ("CPRE"), Act 236, etc.), whether the resource is a designated, mandated, or undesignated resource, and where the resource is found in the PROSYM database and in the LCR tables for reconciliation purposes. We recommend this information be provided in a modified IRP in this proceeding. **(N)**

<u>Economic Evaluation of Portfolios and Sensitivities</u>

21. ORS recommends the Company include post in-service capital costs for new resource additions in its capital cost model and its Present Value of Revenue Requirement ("PVRR") calculations for each Portfolio and each sensitivity of each Portfolio. We recommend this be addressed in a modified IRP in this proceeding. **(N)**

<u>Customer Rate Impacts</u>

22. The average retail rate impacts are an important consideration when assessing whether Portfolios and the pathways reflected in those Portfolios are reasonable. This should be considered in this IRP and future IRPs, but it does not require a modified IRP in this proceeding. **(N)**

23. ORS recommends the Company revise the calculation of the average retail rate impact on customers so that the assumptions and methodologies are consistent with the calculations of the PVRR, except for the levelization of the capital-related costs. We recommend this be included in a modified IRP in this proceeding. (**N)**

<u>Other Considerations – Action Plan</u>

24. ORS recommends the Company provide additional details and status updates about resources included in the action plan, including CT retirements, unnamed energy storage projects, and the nuclear uprates. We recommend this information be included in a modified IRP in this proceeding. **(N)**

<u>Other Considerations – Southeast Energy Exchange Market ("SEEM")</u>

25. ORS recommends that in future IRPs, the Company provide details regarding the status of the SEEM, details regarding important current and planned activities, and information regarding the monetary benefits that have been or could be achieved by implementation of the SEEM. We recommend this be addressed in the future through the Company's stakeholder process. **(L)**

Evolution of the IRP Process in South Carolina

Initiation and Evolution of IRP Process

The Commission initiated a generic proceeding in June 1987 to address least-cost resource procedures based on a comprehensive planning approach for jurisdictional electric utilities.[13] Electric utilities were required to file IRPs in September 1989.[14]

The Commission subsequently approved a more formal IRP process in October 1991.[15] The Commission required utilities to file detailed IRPs every three (3) years and short-term action plans in the intervening years. In addition to the Commission's IRP procedures, the South Carolina legislature passed a bill (Act 449) known as the South Carolina Energy Conservation and Efficiency Act of 1992, adding S.C. Code Ann. § 58-37-40.[16] The definition of an IRP adopted for use in South Carolina is found in S.C. Code Ann. § 58-37-10(2):

> "Integrated resource plan" means a plan which contains the demand and energy forecast for at least a fifteen-year period, contains the supplier's or producer's program for meeting the requirements shown in its forecast in an economic and reliable manner, including both demand-side and supply-side options, with a brief description and summary cost-benefit analysis, if available, of each option which was considered, including those not selected, sets forth the supplier's or producer's assumptions and conclusions with respect to the effect of the plan on the cost and reliability of energy service, and describes the external environmental and economic consequences of the plan to the extent practicable. For electrical utilities subject to the jurisdiction of the South Carolina Public Service Commission, this definition must be interpreted in a manner consistent with the integrated resource planning process adopted by the commission. For electric cooperatives subject to the regulations of the Rural Electrification Administration, this definition must be interpreted in a manner consistent with any integrated resource planning process prescribed by Rural Electrification Administration regulations.

Utilities followed the IRP requirements established by the Commission in its 1991 order until 1998. On February 3, 1998, Duke Energy filed a petition to modify the IRP requirements, which led the Commission to re-evaluate its IRP procedures.[17] On July

[13] Docket No. 87-223-E, Order No. 87-569, June 18, 1987.
[14] Docket No. 87-223-E, Order No. 89-521, May 17, 1989.
[15] Docket No. 87-223-E, Order No. 91-885, October 21, 1991. Attachment A to the Order contained the detailed IRP requirements. Another Order granting clarification and modification was issued on November 6, 1991 (Order No. 91-1002).
[16] www.scstatehouse.gov/billsearch.php?billnumbers=1273&session=109&summary=B
[17] February 3, 1998. Docket No. 87-223-E, Order No. 98-502, July 2, 1998.

2, 1998, the Commission issued Order No. 98-502, which established a simplified set of IRP requirements based on what the Commission observed at the time to be "the changing nature and deemphasis of Integrated Resource Planning."[18]

The state legislature subsequently passed Act 62 also known as the Energy Freedom Act of 2019, which addressed many issues associated with utility planning, including updating and re-emphasizing IRP requirements.[19]

Most recently, the Commission issued Order No. 2020-832, in which it addressed Dominion Energy South Carolina, Incorporated's ("DESC") IRP, the first IRP filed by an electric utility since Act 62 was enacted. In that Order, the Commission addressed various issues of interpretation and application of those new statutory requirements, some of which may be applicable to DEP and DEC in this proceeding.

Act 62 IRP Requirements

Act 62 was signed into law in May 2019. Act 62 updated Section 40 by changing some requirements and adding others that affected not only the electric utilities, but also the Commission, ORS and the State Energy Office ("SEO"). Act 62 applies to all electric utilities in South Carolina.

Section 40 now requires electric utilities to file IRPs that provide more detailed information to the Commission and other parties, and to post the IRPs on both the Commission and utility's websites. Electric utilities are required to file IRPs at least every three (3) years, and to file annual updates with specific information in the intervening years.[20] Section 40(B)(1) sets forth the required information and Section 40(B)(2) sets forth the additional optional information.

Section 40 now requires the Commission to establish a proceeding to review each electric utility's IRP. Interested parties are permitted to intervene and submit discovery. Section 40(C)(1) states the new requirements are intended to allow interested parties to obtain "evidence concerning the integrated resource plan, including the reasonableness and prudence of the plan and alternatives to the plan."

Sections 40(C)1 and (C)2 state the Commission shall issue a final order within 300 days approving the utility's IRP as is, if the Commission "determines that the proposed integrated resource plan represents the most reasonable and prudent means of meeting the electrical utility's energy and capacity needs as of the time the plan is reviewed." However, if the Commission finds that the IRP does not meet that standard, then the Commission is required to either order the utility to make specific modifications to its

[18] Docket No. 87-223-E, Order No. 98-150, February 25, 1998.
[19] Act 62 became effective on May 16, 2019.
[20] S.C. Code Ann. § 58-37-40(D)(1).

IRP or reject the IRP entirely. If the Commission makes one of these determinations, Section 40(C)(3) provides procedures and a timeline that requires the utility to resubmit its IRP and ORS to review the revisions and report its findings to the Commission. Then, the Commission "at its discretion may determine whether to accept the revised integrated resource plan or to mandate further remedies that the Commission deems appropriate."

Section 40(C)2 directs the Commission to consider seven (7) factors as it evaluates whether the IRP is "the most reasonable and prudent means of meeting energy and capacity needs" and determine whether the IRP should be accepted, modified or rejected.

Section 40(D)1 discusses the requirements for IRP updates that are to be filed during the two (2) intervening years between when comprehensive filings are to be made. Section 40(D)2 discusses the procedure for reviewing annual updates, which is different than for the comprehensive filing that utilities must make every three (3) years. For the annual updates, ORS is required to review the utility's filing and submit a report to the Commission containing a recommendation concerning the reasonableness of the annual update. The Commission then must decide if it will "…accept the annual update or direct the electrical utility to make changes to the annual update that the commission determines to be in the public interest."[21]

Commission Consideration of DEP's IRP

The Company notes that the statute "directs the Commission to approve the plan as reasonable and prudent at the time the plan was reviewed by taking into consideration if the plan appropriately balances various criteria addressing reliability, affordability, compliance with environmental regulations, commodity price risk, diversity of supply, and other factors the Commission determines to be in the public interest."[22] The Company asserts that its IRP met that goal.

ORS Approach to Performing this Review

ORS set objectives for the review, analyses and recommendation to determine if the Company met the statutory requirements of Section 40 and to provide a recommendation to approve, modify or reject the Company's IRP. To achieve these objectives, ORS reviewed the Company's IRP, testimony, exhibits, prior IRPs and IRPs filed by other electric utilities, including DESC, Lockhart Power Company, Georgia Power Company, Entergy Louisiana, LLC, PacifiCorp, Kentucky Power Company, and others. ORS also conducted extensive discovery, including six (6) sets with over 79 questions including some multi-part questions, held a technical conference call with the

[21] S.C. Code Ann. § 58-37-40(D)(2).
[22] Direct Testimony of Glen Snider, pg. 36, ln. 3.

Company on October 30, 2020, participated in an IRP Technical conference hosted by the Company for all intervenors on September 18, 2020, and participated in other stakeholder engagement conference calls that the Company hosted throughout the year. In addition, ORS submitted informal questions that requested DEP subject matter experts to review and respond, and reviewed extensive discovery and filings in the parallel North Carolina IRP proceedings.

Compliance with Requirements of Section 40

This section of the ORS Report first addresses the Company's compliance with the specific information requirements listed in the statute (Sections B(1) and B(2)) and then addresses the seven (7) factors set forth in Section C(2) of Act 62 that the Commission is directed to consider in deciding whether the Company's "proposed integrated resource plan represents the most reasonable and prudent means of meeting the electrical utility's energy and capacity needs as of the time the plan is reviewed."[23]

DEP has provided the specific information that addresses Sections B(1) and B(2) of Act 62. ORS has identified opportunities for DEP to improve this IRP and future IRPs, including requesting supplemental information that could assist the Commission in its consideration of the seven factors set forth in Section C(2). In subsequent section of the Report, ORS makes certain recommendations to be reflected in a modified IRP prior to Commission approval in this proceeding and future proceedings and makes additional recommendations for future IRPs.

Statutory Requirements in Section 40(B)

The following section of the ORS Report provides the ORS assessment of the Company's compliance with the Section 40(B)(1) and (2) statutory requirements.

B: An integrated resource plan shall include:

(1)(a): a long-term forecast of the utility's sales and peak demand under various reasonable scenarios.

DEP complied with the requirement to provide a long-term forecast of its sales and peak demand, and provided such forecasts under various reasonable scenarios. The load forecast development process is discussed in Chapter 3 and Appendix C of the Company's IRP.

(1)(b): the type of generation technology proposed for a generation facility contained in the plan and the proposed capacity of the generation facility, including fuel cost sensitivities under various reasonable scenarios.

DEP complied with the requirements to provide generation technology information for new generic resources considered in its IRP, including each of the six Portfolios. In the IRP report, the Company discusses the various potential new generic resource alternatives that it evaluated, which include CTs, reciprocating engines, combined cycle combustion turbines ("CCGT"), coal, nuclear, CHP, wind, solar, other renewables, such as onshore and offshore wind, and battery and other storage technologies. In Appendix

[23] Section 40(C)(1) sets forth the standard of review and Section 40(C)(2) identifies the seven (7) factors.

G of its IRP, the Company discusses the screening process that it used to narrow down the resource alternatives. That section includes a table on page 320 that provides a list of generic resources that were evaluated and the capacities of the resources. In confidential Excel workbooks provided in response to discovery, the Company provided significant technical and cost information obtained from various sources that it used to develop capital-related costs and operating expenses for each of the new generic resources. Once it created the six Portfolios, the Company also conducted fuel cost sensitivities as part of its economic evaluation of the Portfolios.

(1)(c): projected energy purchased or produced by the utility from a renewable energy resource.

DEP complied with this requirement by providing information in Section 5 of its IRP Report concerning both renewable resources that were required to meet state statutory and regulatory obligations (predominantly North Carolina statutory and regulatory requirements) and resources that were economically selected over the resource planning period. The Company identified renewable resource additions and capacity amounts by year in Figure 12-F of the IRP Report.

(1)(d): a summary of the electrical transmission investments planned by the utility.

DEP complied with this requirement by providing information in Appendix L of its IRP Report, in which it discussed its planned or currently under construction transmission investments. It also included information in Chapter 7 of its IRP Report about grid requirements, in which it described the development of initial transmission cost estimates associated with the retirement of some of its coal generating units during the study period (planning horizon), and the siting of additional generation resources for the six (6) Portfolios that were confected and modeled. The Company indicated its projection of transmission investments were provided as high-level estimates for each Portfolio because the new resource additions do not have specific site locations at this stage of the planning process. The Company stated, "Extensive additional study and analysis of the complex interactions regarding future resource planning decisions will be needed over time to better quantify the cost of transmission system upgrades associated with any portfolio."[24]

(1)(e): several resource portfolios developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's service obligations. Such portfolios and evaluations must include an evaluation of low, medium, and high cases for the

[24] DEP 2020 IRP, pg. 56.

adoption of renewable energy and cogeneration, energy efficiency, and demand response measures, including consideration of the following:

i. **customer energy efficiency and demand response programs;**

ii. **facility retirement assumptions; and**

iii. **sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks.**

DEP complied with this requirement by developing six (6) specific Portfolios in which it evaluated a range of demand-side, supply-side, storage and other technologies and services that could be relied on to meet its obligations. DEP conducted sensitivity analyses in which it included estimates of low, medium, and high cases related to fuel and CO_2 costs, and EE/DSM to determine the impacts on the portfolios it evaluated.

The Company conducted several studies to guide the development of its IRP, including performing an updated EE market potential study ("MPS"), and a study to examine the potential for additional winter demand-side peak savings through innovative rates initiatives combined with advanced demand response and load shifting programs that went beyond the scope of the MPS. The demand response study is still on-going and the Company states that it "envisions working with stakeholders in the upcoming months and beyond to investigate and deploy, subject to regulatory approval, additional cost-effective programs identified through this effort."[25] The Company also indicated the preliminary study results are promising and show a potential for the Company moving towards the High EE case in the IRP.

With regard to facility retirement assumptions, the Company conducted a retirement analysis that is described in detail in Chapter 11 entitled, Coal Retirement Analysis. The results of the study show that under either the Base Case with or without CO_2 portfolios, it would be economic to accelerate retirement of coal units compared to the projected coal retirement dates that were included in the DEP 2019 IRP.

(1)(f): data regarding the utility's current generation portfolio, including the age, licensing status, and remaining estimated life of operation for each facility in the portfolio.

The Company complied with this requirement by providing data regarding the utility's current generation portfolio in Appendix B, that includes the age and estimated remaining life of its owned existing generating resources. Additional information in that Appendix includes the winter and summer capacity ratings and fuel type for each

[25] DEP 2020 IRP, Chapter 4, pg. 36.

existing resource, as well as the licensing status of its nuclear and hydro resources.

(1)(g): plans for meeting current and future capacity needs with the cost estimates for all proposed resource portfolios in the plan.

The Company complied with this requirement by ensuring that each of the six (6) portfolios it evaluated would be able to meet expected capacity requirements, providing detailed cost estimates for all new generic resources included in each Portfolio, and providing the PVRR comparisons for all six portfolios based on high, medium and low CO_2 and fuel cost sensitivity cases.[26] The Company also performed sensitivity analyses in which it used the Base Case with CO_2 portfolio and developed comparison cases with high and low levels of renewables, EE, and renewable capital costs. In addition, the Company created sensitivity cases to investigate a shorter operating life assumption for natural gas resources (25 vs 35 years), an increased pumped storage hydro ("PSH") case, and a lower battery storage cost case (capital cost reduced by 15%).

(1)(h): an analysis of the cost and reliability impacts of all reasonable options available to meet projected energy and capacity needs.

The Company complied with the requirement to include an analysis of the cost of all reasonable options by performing both optimization analyses using the System Optimizer Model and production cost analyses using the PROSYM model. Those analyses consider the production costs to operate DEP's generating units including both existing plus future resource additions, and includes capital related revenue requirements based on incremental resource additions to its System. In addition, the company considered cost impacts in another way by considering average retail and residential bill impacts which are useful in assessing customer affordability of the Company's resource plans.

The Company evaluated reliability impacts in several ways. First, DEP contracted with Astrapé to perform a detailed resource adequacy and reliability study, which determined the appropriate planning reserve margin target for the Company. The planning reserve margin target is critical to determining the appropriate level of resources needed to maintain system reliability. Astrapé also performed a study to determine the effective capacity value of storage resources, which it refers to as the Storage Effective Load Carrying Study. Second, as mentioned the Company conducted production cost analyses using PROSYM. In addition to determining the fuel and O&M costs to operate generating resources, PROSYM also evaluates the reliability of the system by determining the amount of unserved energy that may be expected in any given year for each portfolio and assigns a cost to that energy. ORS concluded that the Company's resource adequacy analyses are reasonable.

[26] DEP 2020 IRP, Table A-15.

(1)(i): a forecast of the utility's peak demand, details regarding the amount of peak demand reduction the utility expects to achieve, and the actions the utility proposes to take in order to achieve that peak demand reduction.

The Company complied with the requirement to provide a forecast of its peak demand, and it provided details regarding the amount of peak demand reduction the Company expects to achieve. Chapter 3 and Appendix C of the IRP report provide information regarding the development of the three retail load forecasts for the Residential, Commercial, and Industrial classes, and explain the key drivers that influence the load forecasts. Chapter 4 and Appendix D of the IRP report provide an overview of the EE and DSM. DEP includes DSM programs, also referred to as demand response programs, for both residential and non-residential customers, though the programs to date have mostly been geared towards controlling summer peak demand. The Company also recognizes the importance of controlling winter peak demand, and as such has commissioned a study to specifically examine the potential for additional winter demand-side peak savings through innovative rates initiatives combined with advanced demand response and load shifting programs. The Company has engaged Tierra Resource Consultants, who collaborated with Dunsky Energy Consulting and Proctor Engineering to perform the study. The consultant's study was not completed at the time DEP filed its IRP; however, the Company discussed that when the results are available it will work with stakeholder to further develop the programs identified in the study.

(B)(2): An integrated resource plan may include distribution resource plans or integrated system operations plans.

The Company has addressed this optional requirement and describes distribution resource plans most significantly in Chapter 15, where it discusses plans for Integrated System & Operations Planning ("ISOP"). The Company believes this effort will be important "to address the trends in technology development, declining cost projections for energy storage and renewable resources, and customer adoption of electric demand modifying resources such as roof-top solar and electric vehicles ("EV"s)."[27] According to DEP, the reason more advanced distribution planning is necessary is to be able to better analyze the distribution and transmission systems in order to account for increasing variability of generation and two-way power flows on the distribution system, which will require significant changes to modeling inputs and tools. The Company states that it is committed to implementing ISOP planning in the 2022 IRP.

In addition, in Chapter 4 of the IRP the Company discussed its plans for implementing Integrated Voltage/VAR Control ("IVVC"), which it states is part of the proposed Duke

[27] DEP 2020 IRP, pg. 125.

Energy Carolinas Grid Improvement Plan and involves the coordinated control of distribution equipment in substations and on distribution lines to optimize voltages and power factors on the distribution grid.

Statutory Requirements in Section 40(C)(2)

The statute directs the Commission to consider seven (7) factors in making its determination as to whether the IRP "represents the most reasonable and prudent means of meeting the electrical utility's energy and capacity needs at of the time the plan is reviewed." The following are the factors that must be considered:

C(2): The commission, in its discretion, shall consider whether the plan appropriately balances the following factors:

(a) resource adequacy and capacity to serve anticipated peak electrical load, and applicable planning reserve margins.

(**b) consumer affordability and least cost.**

(c) compliance with applicable state and federal environmental regulations.

(d) power supply reliability.

(e) commodity price risks.

(f) diversity of generation supply.

(g) other foreseeable conditions that the commission determines to be for the public interest.

The Commission is required to consider these seven (7) factors in evaluating whether it believes that DEP's IRP "represents the most reasonable and prudent" means of meeting its capacity and energy requirements, and in doing so the Commission is permitted to use its discretion to judge the factors that it believes should receive a greater decision making weighting compared to the other factors. The Commission recently issued its order in DESC's 2020 IRP (Order No. 2020-832) in which it stated that it was providing "guidance on its interpretation and expectations for compliance with the statute for the public interest not only for DESC, but also for other electrical utilities."[28]

The Commission provided additional guidance on the standard that a utility's IRP must meet and the factors that the Commission will use to evaluate a utility's IRP, as follows:

[28] December 23, 2020, Commission Order No. 2020-832, Docket No. 2019-226-E, pg. 7.

- **Reasonable** – "the plan must be 'reasonable,' meaning it is rational, logically consistent, and the result of sound judgment. In the context here, this requires consideration of whether the utility's plan meets the requirements of Act 62 and comports with industry norms and widely-known IRP best practices." [29]
- **Prudent** – "it gives due consideration to actual and foreseeable future conditions and risks. Such consideration should take into account the relative costs and benefits of avoiding potential future risks, such as regulatory, capital, or fuel risks."[30]
- **Detailed Information** – "the IRP and the record must provide sufficient information about each of the seven balancing factors to enable the Commission to determine if the IRP appropriately balances each of them. Act 62 also requires that the plan must represent the most reasonable and prudent means of meeting the electrical utility's energy and capacity needs as of the time the plan is reviewed."[31]
- **Best Available Tools and Modeling Capabilities** – "This is a significant standard that implies that IRP requirements should not be static, but rather should continuously improve over time as standards and practices improve and evolve. It also implies that a utility may not do the bare minimum, but rather must ensure that its IRP is the result of serious planning and consideration using the best available data and tools available to it."[32]
- **Risk** – "Act 62 requires that the Commission balance a number of factors, including "commodity price risks" and "diversity of generation supply."[33]

The Commission emphasized that although cost is an important consideration, "reasonableness" and "prudence" do not require that the utility simply select the least-cost resource plan, given the inherent uncertainty of sensitivity assumptions for future conditions.

These are guidelines for the evaluation of a utility's IRP and balancing the statute's seven (7) specific factors. As previously noted, DEP evaluated six (6) portfolios designed to consider regulatory/environmental, capital cost, and commodity price risks. The Company conducted a detailed coal retirement study and produced an economic coal retirement schedule as well as a more aggressive coal retirement schedule based on the earliest possible dates that coal units could be retired. The Company conducted evaluations of low, base, and high levels of renewable resources, and EE, all of which provide relevant insight into the path forward, the options it could pursue in the future, and whether that path forward provides sufficient flexibility to allow the utility to alter its

[29] *Id.* pg. 12.
[30] *Id.* pg. 13.
[31] *Id.* pg. 13.
[32] *Id.* pg. 13.
[33] *Id.* pg. 14.

course as conditions change.

With regard to the question of whether DEP has provided the necessary information required by Section 58-37-40(B), DEP did comply with all of the requirements of Section 40(B). However, as noted in the ORS Report, there are improvements that could be made to DEP's IRP. ORS concluded that many of the issues raised could be addressed immediately or in the near future working under the guidance of the stakeholder process.

With regard to the items that the Commission discussed in the DESC order, based on the evaluation of DEP's IRP, ORS concluded that DEP conducted a thorough IRP evaluation. The Company relied on industry standard approaches, such as using optimization modeling tools, performed stochastic based reliability analyses, used load forecasting and production cost modeling tools that are widely used in the industry, and retained industry experts to conduct various analyses that were either integral to its current IRP study (e.g., Nexant, Inc. produced an EE MPS), or will be in the near future (Tierra Resource Consultants conducted a demand response study). In addition, the Company demonstrated that it is currently developing new modeling approaches that will likely lead to further integration of transmission and distribution planning (ISOP) with its current supply-side and demand-side planning processes, and its current plan is to utilize and integrate these new tools in developing its 2022 IRP.

In the six Portfolios evaluated, the Company demonstrated that it evaluated a wide range of resource alternatives, including many advanced resource alternatives including small modular nuclear reactors and offshore wind. The Company developed two base cases; one that reflects the regulatory and statutory requirements that exist today, without consideration of CO_2, and another that includes consideration of CO_2 policy. One issue in this proceeding is whether DEP has included an appropriate level of renewable resources in its preferred resource plan, which DEP has identified to be its Base Case without CO_2 plan.

In the Base Case without CO_2 plan, DEP included 1,662 MW of base solar, 339 MW of base solar plus storage and 117 MW of base battery energy storage, with 481 MW of battery storage economically selected. This is significant and could increase in future IRPs as statutory, regulatory, and other circumstances change.

In the Base Case with CO_2 plan, the Company explicitly recognizes the possibility that a CO_2 policy will be implemented, essentially providing a risk adjusted plan that overlays this possibility on the Base Case without CO_2 plan. In the Base Case with CO_2 plan, DEP included the same amount of base solar and solar plus storage, but also economically selected an additional 1,425 MW of solar + storage and 656 MW of grid-tied battery capacity over the planning horizon, plus it adds 600 MW of onshore wind to the portfolio. With this increase in renewable resources over the planning horizon, there is 1,224 MW less CCGT capacity added, and a 2,285 MW reduction in the amount of CT capacity added.

At this time, DEP supports the Base Case without CO_2 case as its preferred plan for purposes of avoided cost proceedings, value of solar calculations, cost-effectiveness, and DSM evaluations.[34] It is likely that they choose this plan because 1) it reflects currents regulatory and statutory policy that is in place today, 2) it represents the least cost plan under current policy assumptions, 3) it includes a considerable amount of new renewable resources, 4) it relies on resources that are commercially available today, and 5) it is a flexible plan that can easily be modified to allow more renewable resources to be added if a CO_2 policy is implemented.

However, the Base Case with CO_2 case offers the advantages of including additional amounts of solar and solar plus battery storage capacity, and is based on resource types that are commercially available today. Note, however, that the premise of the Base Case with CO_2 plan is that CO_2 policy will be implemented someday, yet the date when the CO_2 policy would begin and the cost associated with that policy, such as a CO_2 tax, is highly uncertain and may not be known for some time.

[34] ORS AIR 3-1, part d.

Evaluation of DEP's IRP

Load and Energy Forecast

Overview

This section of the report discusses the Company's 2020 IRP load (peak demand) and energy forecasts, both of which are essential elements of a least cost resource plan. ORS reviewed the methodology, models, and forecast results to determine if they are reasonable and meet the requirements of Act 62, Section 40; specifically, Section 40B(1)(a). As discussed below, ORS determined that the forecasts meet the requirements of Act 62, are reasonable, and represent a high level of methodological sophistication. DEP's load and energy forecasts cover the 15-year period 2021 through 2035. During the forecast period, the Company projects an average annual growth rate of 0.8% in energy requirements, and average annual growth rates of 0.9% in summer and 0.9% in winter peak loads. Each of the forecasts reflect embedded EE, adjusted to reflect roll-offs of EE program impacts as they reach their expected termination date. Incremental (new) EE is then reflected as a separate adjustment to the peak load forecast. The peak load forecasts do not include demand reductions that can be called by the Company pursuant to DSM. DSM is reflected as a capacity resource in the IRP.

Forecast Analysis

The Company develops econometric based models to forecast energy sales to the residential, commercial, and industrial classes. For the residential and commercial classes, DEP develops average kilowatt-hour (kWh) use per customer models using a statistically adjusted end-use ("SAE") methodology and a separate projection of the number of customers. These types of models incorporate a significant amount of detailed information on customer end-uses (e.g., HVAC equipment, household appliances, commercial building characteristics) that permit modeling of end-use efficiency improvements during the forecast horizon, both those due to federal or state mandates and those due to economic factors and technological innovation. These types of SAE models, in theory, provide a more precise measure of the behavioral factors that influence customer usage. Projections of the number of customers is driven by population projections.

For the industrial sector, the Company uses traditional econometric models in which usage is driven by manufacturing activity indices (Industrial Production Index) and the price of electricity.

Tables 1 to 3 below present the econometric models used by the Company to forecast residential, commercial, and industrial MWh sales. The residential and commercial forecasts are derived based on complex models that incorporate three composite variables (e.g., heating, cooling, other), plus indicator variables that provide a differentiation for each month. The detailed end-use saturation and efficiency data, electric price and income variables are contained in each of the composite variables. The models are estimated using monthly data for the period January 1, 2011 through December 31, 2019. As can be seen from the model statistics in Tables 1 and 2, the R-Squared (R^2) results indicate that the models explain about 90%, or more, of the variation in average use per customer over the 120-month estimation period. In addition, the t-statistics on the key driving variables are high for the residential model, and reasonable for the commercial model.

Table 1
Residential Use Per Customer Model

Adjusted Observations	107
Deg. of Freedom for Error	80
R-Squared	0.961
Adjusted R-Squared	0.948

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
mStruct_RES_SPR20.XHeat1_B	0.003	0	25.124	0.00%	End-use Heating
mStruct_RES_SPR20.XCool1_B	0.006	0	36.348	0.00%	End-use cooling
mStruct_RES_SPR20.XOther_B	0.001	0	91.6	0.00%	End-use non-weather sensitive
mIndicators.JAN11	1.916	0.052	36.867	0.00%	
mIndicators.FEB11	0.177	0.053	3.358	0.12%	
mIndicators.JUN11	0.254	0.052	4.847	0.00%	
mIndicators.OCT12	-0.109	0.053	-2.07	4.16%	
mIndicators.APR13	0.236	0.053	4.484	0.00%	
mIndicators.SEP13	-0.117	0.052	-2.224	2.90%	
mIndicators.FEB14	0.253	0.053	4.749	0.00%	
mIndicators.APR14	0.217	0.053	4.12	0.01%	
mIndicators.AUG14	-0.113	0.053	-2.148	3.48%	
mIndicators.NOV14	-0.161	0.052	-3.073	0.29%	
mIndicators.DEC14	0.177	0.053	3.348	0.12%	
mIndicators.MAR15	0.45	0.052	8.571	0.00%	
mIndicators.MAY15	-0.107	0.053	-2.038	4.48%	
mIndicators.JUN15	0.159	0.052	3.031	0.33%	
mIndicators.NOV15	-0.185	0.053	-3.505	0.08%	
mIndicators.JAN16	-0.195	0.055	-3.513	0.07%	
mIndicators.MAR16	0.178	0.053	3.393	0.11%	
mIndicators.NOV16	-0.114	0.053	-2.166	3.33%	
mIndicators.JAN17	0.161	0.053	3.025	0.33%	
mIndicators.JAN18	0.249	0.056	4.425	0.00%	
mIndicators.FEB18	0.219	0.052	4.175	0.01%	
mIndicators.MAR18	-0.149	0.053	-2.829	0.59%	
mIndicators.FEB19	0.176	0.053	3.342	0.13%	
mIndicators.NOV19	-0.107	0.053	-2.043	4.44%	

Table 2
Commercial Model

Adjusted Observations	108
Deg. of Freedom for Error	88
R-Squared	0.924
Adjusted R-Squared	0.908

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
CONST	822420	130965	6.28	0.00%	Constant term
mStruct_COM_SPR20.XHeat_B	1145035.6	176212.5	6.498	0.00%	End-use Heating
mStruct_COM_SPR20.XCool_B	335745.36	13988.62	24.001	0.00%	End-use cooling
mStruct_COM_SPR20.XOther_B	12298.2	8918.494	1.379	17.14%	End-use non-weather sensitive
mIndicators.AUG13	110009.32	42690.25	2.577	1.16%	
mIndicators.APR14	85896.211	42824.11	2.006	4.79%	
mIndicators.OCT14	86746.812	42320.1	2.05	4.34%	
mIndicators.NOV14	-178171.5	42306.27	-4.211	0.01%	
mIndicators.MAR15	119432.19	42295.65	2.824	0.59%	
mIndicators.MAY15	-76520.12	42655.24	-1.794	7.63%	
mIndicators.SEP15	124992.31	42253.72	2.958	0.40%	
mIndicators.NOV15	-112672.9	42339.98	-2.661	0.93%	
mIndicators.DEC16	-79415.02	42817.57	-1.855	6.70%	
mIndicators.NOV17	-75567.95	42751.19	-1.768	8.06%	
mIndicators.DEC17	-107022.4	43617.44	-2.454	1.61%	
mIndicators.JAN18	114265.92	44948.54	2.542	1.28%	
mIndicators.MAR18	-84939.62	42799.32	-1.985	5.03%	
mIndicators.DEC18	-195942.9	43444.45	-4.51	0.00%	
mIndicators.MAR19	-80530.91	42810.77	-1.881	6.33%	
mIndicators.NOV19	-155668.8	43227.52	-3.601	0.05%	

For the industrial model, shown in Table 3, which is a generally standard type of industrial sales econometric model, the R^2 is somewhat lower than reported for the residential and commercial models, indicating that the model explains about 80% of the variation of monthly industrial sales over the 120-month estimation period. All of the driving variables (e.g., industrial production) are reported to be statistically significant.

Table 3
Industrial Model

Adjusted Observations	108
Deg. of Freedom for Error	82
R-Squared	0.812
Adjusted R-Squared	0.755

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
ECON_SPR2020.Industrial_Production_Index_Consensus	6582.67	730.043	9.017	0.00%	North Carolina Industrial Production Index
SALES_B_IND.Price_L	-25470.615	9180.341	-2.774	0.68%	Industrial Prices, lagged 7 months
mBilledWeather.JUL_CDD65	266.227	35.444	7.511	0.00%	CDD Base 65 for July
mBilledWeather.AUG_CDD65	329.937	33.492	9.851	0.00%	CDD Base 65 for August
mBilledWeather.SEP_CDD65	197.203	43.062	4.579	0.00%	CDD Base 65 for September
CUST_IND.Filled	76.799	16.876	4.551	0.00%	Industrial customer forecast
mIndicators.MAY11	114985.544	41219.445	2.79	0.66%	
mIndicators.APR12	88307.828	43474.254	2.031	4.55%	
mIndicators.OCT12	87018.512	43302.869	2.01	4.78%	
mIndicators.JAN13	88066.572	41212.215	2.137	3.56%	
mIndicators.MAR13	-99157.205	41315.545	-2.4	1.87%	
mIndicators.APR13	141248.204	43447.686	3.251	0.17%	
mIndicators.JUL13	171155.164	42095.536	4.066	0.01%	
mIndicators.NOV14	-88487.692	40589.974	-2.18	3.21%	
mIndicators.JUN15	115536.592	40545.811	2.85	0.55%	
mIndicators.DEC16	-91469.299	40605.711	-2.253	2.69%	
mIndicators.MAY17	151939.232	40708.113	3.732	0.04%	
mIndicators.DEC17	-147529.084	41187.222	-3.582	0.06%	
mIndicators.MAR18	-112987.78	40883.73	-2.764	0.71%	
mIndicators.SEP18	-164500.028	43856.08	-3.751	0.03%	
mIndicators.DEC18	-172260.937	41506.351	-4.15	0.01%	
mIndicators.JAN19	87679.192	41227.893	2.127	3.64%	
mIndicators.MAR19	-113502.974	41141.277	-2.759	0.71%	
mIndicators.NOV19	-90048.137	42005.823	-2.144	3.50%	
mCalendar.Apr	32266.767	16443.446	1.962	5.31%	
mCalendar.Oct	92503.797	15387.934	6.011	0.00%	

Table 4 presents the peak load econometric model that is used to forecast both the summer and winter peaks. Like the residential and commercial models, the peak load model is estimated using monthly data and is primarily driven by composite variables reflecting cooling load, heating load and non-weather sensitive load. The composite variables consist of heating and cooling residential and commercial sales during the maximum combined month (i.e., MWh sales the month in which the maximum combined residential and commercial sales occur in the year). The non-weather sensitive composite variable consists of industrial sales and other sales. This type of model structure provides a link between the Company’s electric sales forecast and the summer/winter peak load forecast and incorporates the end-use saturation and efficiency information that is modeled in the residential and commercial sales forecasting models. The statistical results presented for the peak load model indicate the model explains about 90% of the variation in peak load over the estimation period, which is 2013 to 2019.

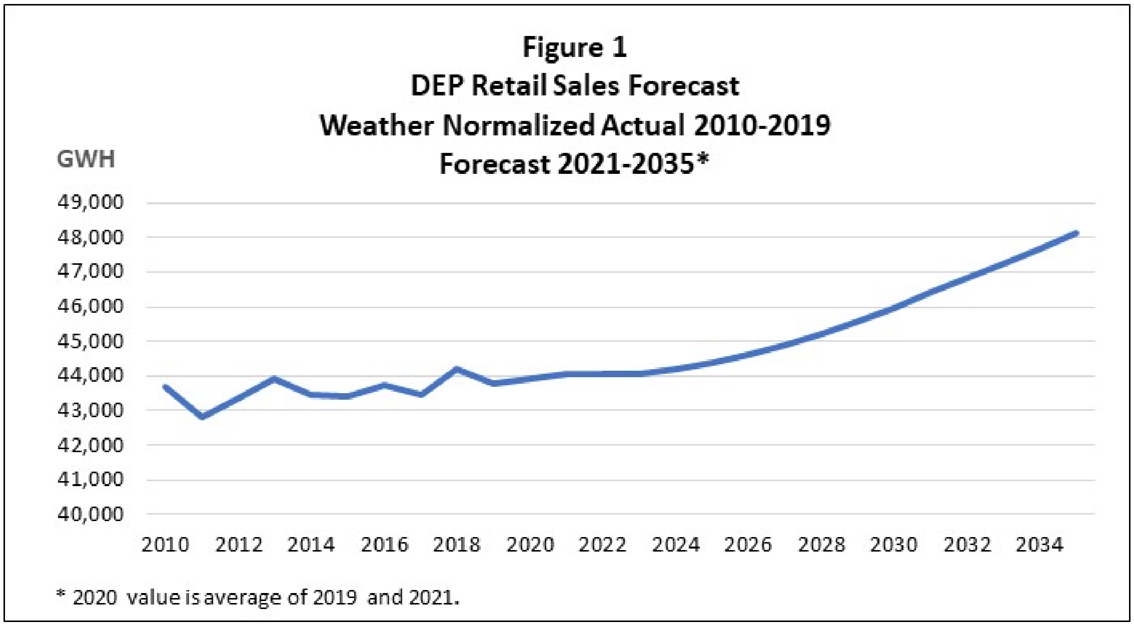
Table 4
Summer/Winter Peak Load Model

Adjusted Observations	84
Deg. of Freedom for Error	67
R-Squared	0.891
Adjusted R-Squared	0.865

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
mPkEndUse_SPR20.CoolVar	161.605	11.12	14.533	0.00%	Peak End-use cooling
mPkEndUse_SPR20.HeatVar	108.837	7.242	15.028	0.00%	Peak End-use Heating
mPkEndUse_SPR20.BaseVar	0.014	0	38.322	0.00%	Peak End-use non-weather sensitive
mIndicators.JAN13	-1078.833	391.776	-2.754	0.76%	
mIndicators.APR13	-1043.879	386.927	-2.698	0.88%	
mIndicators.JUN13	1024.993	383.259	2.674	0.94%	
mIndicators.JAN14	-1024.797	420.14	-2.439	1.74%	
mIndicators.FEB14	-1535.056	397.433	-3.862	0.03%	
mIndicators.OCT14	-874.379	392.286	-2.229	2.92%	
mIndicators.FEB15	778.792	404.296	1.926	5.83%	
mIndicators.APR15	-959.903	387.095	-2.48	1.57%	
mIndicators.OCT15	-1369.817	389.977	-3.513	0.08%	
mIndicators.DEC15	-1285.474	385.892	-3.331	0.14%	
mIndicators.MAR17	1129.032	384.263	2.938	0.45%	
mIndicators.FEB18	-1189.098	389.187	-3.055	0.32%	
mIndicators.MAR18	1225.83	385.547	3.179	0.22%	
mIndicators.MAR19	925.987	383.856	2.412	1.86%	

Figure 1 shows the Company's Retail MWh sales forecast for the IRP planning period of 2021 through 2035, together with weather normalized historical retail sales for the period 2010 through 2020.[35] Because wholesale contract requirements changed periodically during the historic period, ORS focused on retail sales (total energy sales less wholesale sales). During the 10-year period through 2019, total weather normalized retail sales grew at only 0.02%, while the Company projects sales growth over the next 15 years to be 0.63%.[36] Essentially, during the past 10 years, DEP has had no retail sales growth. During the forecast horizon, the Company is projecting retail sales growth, primarily in the residential sector.

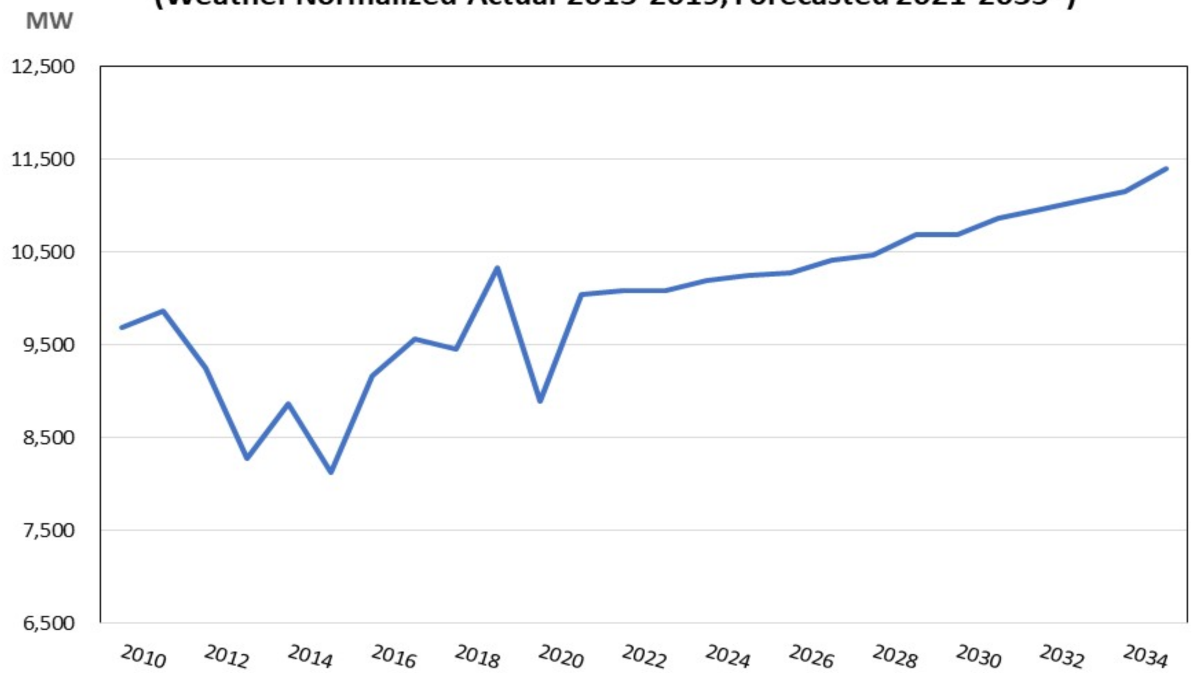
[35] The value for 2020 is calculated as the average of 2019 and 2021.
[36] The forecasted MWh sales do not include the effects of incremental EE programs.



For resource planning purposes, the winter peak demand forecast is the most significant factor. Figure 2 shows the Company's winter peak load forecast, excluding wholesale load, over the IRP planning period of 2021 through 2035, together with corresponding weather normalized historical peaks for the period 2010 through 2020.[37] During the 2010 through 2019 period, winter peak load, excluding wholesale load, grew at 0.7% per year on average, while the Company projects the winter peak load, excluding wholesale load, to grow by 0.9% over the next 15 years.

[37] The value for 2020 is calculated as the average of 2019 and 2021.

Figure 2
DEP Winter Peak Load - Excluding Wholesale
(Weather Normalized Actual 2015-2019, Forecasted 2021-2035*)



* 2020 value is the average of 2019 and 2021

ORS evaluated the performance of the Company's recent sales and winter peak load forecast on the basis of one-year ahead forecast errors. While a 15-year IRP forecast represents a long-term planning forecast, forecast errors on a one-year ahead basis provide some measure of the performance of the forecasts over a longer term. In particular, given the likely forecast errors associated with the key driving variables, such as income and industrial production, evaluation of a one-year ahead forecast error provides information about the performance of the forecasting models themselves, rather than the performance of the driving variables. Table 5 summarizes the one-year ahead retail energy forecasting error for the period 2014 through 2019. The forecast error is calculated as the percentage difference between the forecast for the next year compared to the weather normalized actual retail energy sales for that year. For example, the retail energy sales forecast prepared in 2014 for 2015 is compared to the weather normalized actual retail energy sales for 2015. Over the six-year period, the average one-year ahead energy forecast error for DEP is an over-forecast of 1.0%. On a combined DEP/DEC base, the average retail energy forecast error is an over-forecast of 0.8%.

Table 5
DEP One-Year Ahead Retail Energy Forecast Error

Year IRP Forecast Prepared	Forecast Year	Weather Normalized Actual Retail Sales (GWH))	IRP Forecasted Retail Sales (GWH)	Over/(Under) Forecast (GWH)	One-Year Ahead Forecast Error (%)
2014	2015	43,420	43,537	117	0.3%
2015	2016	43,753	43,937	184	0.4%
2016	2017	43,446	43,749	304	0.7%
2017	2018	44,213	44,306	93	0.2%
2018	2019	43,765	44,484	720	1.6%
2019	2020*	39,595	40,638	1,043	2.6%
Average					1.0%

* Data through November 2020
Source: Response to ORS 4-4

Table 6 summarizes the one-year ahead winter peak load forecasting error for the period 2014 through 2019. Over the six-year period, the average one-year ahead winter peak load forecast error for DEP is an under-forecast of 4.9%. While this appears to be relatively high, when this result is coupled with the same average one-year ahead winter peak forecast error for DEC, the combined system one-year ahead error is only a 1% under-forecast.

Table 6
DEP One-Year Ahead Winter Peak
Forecast Error

Year IRP Forecast Prepared	Forecast Year	Weather Normalized Actual Winter Peak (MW)	IRP Forecasted Winter Peak (MW)	Over/(Under) Forecast (MW)	One-Year Ahead Forecast Error (%)
2014	2015	13,377	12,429	(948)	-7.6%
2015	2016	13,556	12,727	(829)	-6.5%
2016	2017	14,356	13,158	(1,198)	-9.1%
2017	2018	14,797	13,273	(1,524)	-11.5%
2018	2019	14,640	14,011	(630)	-4.5%
2019	2020	13,079	14,473	1,394	9.6%
Average					-4.9%

Source: Response to ORS 4-5

Section 40B(1)(a) requires that a utility include a long-term forecast of the sales and peak demand under various reasonable scenarios. In addition to its base load and energy forecast, the Company also developed high and low case forecasts in order to evaluate the effects of alternative economic projections on the IRP resource expansion plans. These high and low case forecasts are based on alternative economic projections by Moody's Analytics.[38] In addition, the Company evaluated the impacts on IRP resource expansion plans from alternative scenarios of EE, DSM and EV penetration.

Conclusions – Load and Energy Forecasts

Based on the review of the Company's methodologies, models and independent assumptions regarding future population growth, economic activity, and end-use efficiency, ORS concluded that the load and energy forecasts are reasonable. Though the Company is projecting future MWh and peak load growth to be greater than the historic period (see Figures 1 and 2), ORS concluded that the forecasts are reasonable. The Company's methodology is reasonable and reflects a high level of sophistication. Notwithstanding this, we recommend the IRP Report include additional detail regarding the specific models and statistical results that underlie the Company's energy sales and peak load forecasts. While the IRP Report contains a technical appendix that discusses the forecast methodology and results, the appendix does not present the actual

[38] IRP Report, Appendix A.

econometric models used to develop the forecasts. In particular, the Company's models incorporate multiple composite variables that represent the main drivers of the forecasting models (e.g., electric price, income, end-use saturation, and efficiency). Even in response to discovery, the Company did not initially provide this detailed information. While this level of detail is not needed in the IRP Report itself, we recommend the Company enhance its load and energy forecast appendix to include a more comprehensive presentation of its forecasting methodology.

ORS concludes that the Company's load and energy forecast complies with the requirements of Section 40, as amended by Act 62.

Recommendations – Load and Energy Forecasts

1. We recommend the Company provide a technical appendix that more fully describes each of the models, presents the statistical results and shows the individual energy and peak load forecast results that were actually developed. While DEP's IRP provides an overview of this information, it does not provide the detail necessary to fully evaluate the entire forecast. This detail was provided in response to discovery in this proceeding, however, we recommend this level of detail be included in future IRPs as part of a comprehensive technical appendix. **(L)**

Resource Adequacy – Reserve Margin Issues

Overview

This section of the ORS Report addresses the Company's resource planning reserve margin, which drives, to a large extent, the need for generating resources in the 2020 IRP. The Company's resource adequacy analysis for the 2020 IRP was performed by Astrapé using its Strategic Energy and Risk Valuation Model ("SERVM"). SERVM is used by Astrapé to develop both the loss of load expectation ("LOLE") based reserve margin calculations and the economically optimal reserve margins. SERVM models each of the key factors that impact reliability – the ability of the Company's generating resources at various reserve margins to meet customer load without exceeding the 1 day in 10-year LOLE criterion. These key factors include:

1. The effect of temperature on load and the historic temperature distribution.
2. Generator outage characteristics, including the effect of extreme cold weather on generator availability.
3. The distribution of likely errors in the peak load forecast (other than errors related to weather, which is reflected in item 1 above.)

4. The amount of tie-line MW support that can be imported from neighboring systems ('market assistance') during emergencies.

The model performs multiple Monte-Carlo simulations reflecting random outcomes of these factors to estimate the LOLE for a range of reserve margins.[39] The SERVM analysis is performed for a single base year of 2024. The final reserve margin is determined by identifying the LOLE needed to achieve the 1 day in 10-year criterion.

DEP proposes to utilize a planning reserve margin of 17% for the winter peak and 15% for the summer peak over the IRP planning period 2021 to 2035. This is consistent with the Company's reserve margin targets established in the 2016 IRP. The constraining criterion used for resource planning is the winter peak. In other words, if the Company has sufficient capacity resources to meet the winter reserve margin target, it will also meet the summer reserve margin target. Though the Company's 2020 Resource Adequacy Study showed that DEP required a 19.25% winter peak reserve margin to meet a 1 day in 10-year LOLE, DEP has used a 17% reserve margin in the 2020 IRP based on the results of a combined DEP/DEC resource adequacy analysis that showed that a joint system 16.75% winter reserve margin would be adequate to meet the 1 day in 10-year LOLE criterion. It is important to note that the 19.25% reserve margin assumes that the Company will have access to emergency capacity from other interconnected utilities (Astrapé refers to this as market assistance). This is a reasonable assumption in this type of resource adequacy analysis. The winter reserve margin needed to achieve an LOLE of 1 day in 10-years without any tie-line support from interconnected utilities is 25.5%. In the Base case, which assumes external market tie-line support, all of the loss of load occurs during the four winter months of December, January, February, and March. There are "0" loss of load events in the other eight months during the year as long as the winter reserve margin is 10% or greater.

The Company also presents economically optimal reserve margin calculations for both the summer and winter peak periods. These economically optimal reserve margins are determined using a least cost methodology that considers the tradeoff between the cost of providing reserves in terms of additional simple cycle combustion turbine capacity and production costs, versus the cost to customers of failing to meet customer load (customer outage costs). The analysis is similar to the basic LOLE analysis but includes these economic costs and benefits in the determination of a target reserve margin. Based on the optimal economic reserve margin analysis, the optimal winter

[39] The model performs a separate Monte-Carlo simulation for 10 selected reserve margins ranging from 6% to 23%. These results are then used to develop a regression model relating winter peak reserve margins and LOLE that provides a full range of possible results over the range of 8% to 25%. The regression curve essentially is used to interpolate the results between the tested reserve margin levels.

peak reserve margin is only 10.25%. As explained by Astrapé in its report (page 12), the reason for the very low economically optimal winter peak reserve margin is that there are very few hours during the winter period when loads are not met with a low level of reserves. While a 10.25% winter period reserve margin would result in inadequate resources when considered based on a strict reliability evaluation, in other words, just considering LOLE results, there would be relatively few hours during the winter that would be affected. At the same time, a 10.25% winter reserve margin would provide sufficient reserves (22%) in the summer to avoid a high level of outages during many more hours. The optimal economic reserve margin weighs this winter cost of failing to meet customer needs for a relatively few hours to the cost of additional CT capacity to avoid these customer outages. Since the customer outage cost in the summer period is relatively small, the net effect is a low 10.25% winter peak reserve margin target. Of course, this means that there would be hours during the winter period when customer outages occur. Based on the LOLE analysis, a 10% winter period reserve margin would result in an LOLE of 0.23, meaning a loss of load expectation of 1 day every 4.5 years, versus a traditional 1 day in 10-year criterion.

Both Astrapé and DEP rely on the results of the LOLE analysis using a 1 day in 10-year criterion, rather than the economically optimal reserve margin results. ORS agrees with this position for a number of reasons. First, our experience with other utilities is that meeting the 1 day in 10-year LOLE target is considered a minimum reserve margin criterion, even if an optimal reserve margin analysis is performed. For example, Southern Company, which also performs an economically optimal reserve margin analysis, uses the LOLE results as a floor. If the economically optimal reserve margin exceeds the LOLE 1 day in 10-year result, then the economically optimal reserve margin would be favored. If, as in the case of DEP, the economically optimal reserve margin is lower than the level that would achieve an LOLE of 1 day in 10-year level of reliability, the higher LOLE based result is used.

Detailed Resource Adequacy Review

ORS reviewed the Company's 2020 Resource Adequacy Study and the associated workpapers provided by the Company in response to discovery. While we reviewed both the basic LOLE analysis and the economically optimal reserve margin study, our primary focus was on the LOLE analysis because 1) this is the analysis relied on by the Company in the 2020 IRP, and 2) the results of the optimal economic reserve margin analysis are not consistent with a reasonable level of reliability for a utility, such as DEP that is not part of a larger regional transmission organization.

As discussed above, the SERVM model is used to perform both analyses. The optimal economic reserve margin study includes two additional components beyond those modeled in the LOLE analysis. These additional components are: 1) the cost to customers of outages and 2) the revenue requirement cost to provide alternative various levels of reserve capacity - primarily reflecting combustion turbine capital costs, production costs and emergency power costs. While the second of these, the cost associated with various levels of reserve capacity is readily straightforward because it relies on production cost analysis and the revenue requirements of combustion turbine capacity, the cost of customer outages is highly uncertain because it relies on customer surveys to broad-based rate classes (residential, commercial, industrial) that ask these customers to state the costs of power outages of varying durations at various seasons of the year. From a big-picture perspective, a reserve margin based on meeting the industry standard of 1 day in 10-years is simply the reserves needed to meet a long-held agreed to level of reliability, without looking at the costs or benefits of doing so. The criterion is simply based on answering the question, what level of reserves are needed to meet this standard. The economically optimal methodology goes beyond this and attempts to answer the question, what level of reserves do customers desire recognizing that they have to pay more to achieve higher levels of reliability. This framework examines the tradeoff between the cost of reserves versus the benefits of those reserves. Theoretically, the economically optimal method is rational – it provides customers with the level of reliability that they are willing to pay for, based on their cost of not having this reliability (for example, lost manufacturing production or spoiled food). The problem, as noted above, is the measurement of this value to customers. The LOLE method, on the other hand, does not address this value issue. Rather, it assumes that there is a minimum level of reliability that customers demand or insist upon. Capacity reserves are added to achieve this level, without actually asking customers if they are receiving value from this level of reliability commensurate with the cost of achieving it. This is similar to transmission planning, when performed strictly to meet reliability criteria.

Common to both analytical frameworks are the major inputs into SERVM of load curves reflecting 39 years of weather experience, forced outage rates of generating resources, especially during extreme cold weather events that impact the ability to serve load during winter peaks, the assumed distribution of load forecasting errors on peak loads and the assumed tie line support in MW provided by neighboring utility systems.

ORS reviewed the Company's modeling and assumptions for each of these inputs. The SERVM analysis is performed for a single year (2024) under 39 possible weather years (1980-2018). A model is estimated to develop the relationship between hourly load and weather using load and weather data for the five-year period January 2014 to September 2019.[40] These load shapes are then scaled to conform to the Company's

[40] The model is developed using a neural net modeling approach that identifies the most important weather attributes impacting hourly loads.

2024 load and energy forecast. This produces 39 sets of 2024 hourly load shapes reflecting weather conditions that have occurred in the past 39 years. The SERVM analysis assumes that each of the 39 years of historic weather (1980 to 2018), and the corresponding hourly load has an equal chance of occurring.

There are a number of concerns raised by this type of analysis. First, there is the issue of whether it is reasonable to assume an equal probability of each weather year occurring. More specifically, whether more recent weather patterns are more likely due to climate change. The SERVM analysis assumes that the weather in each year over the past 39 years reflects sample observations from a static weather population. This issue has a significant impact on the outcome of the analysis, as we will discuss. Specifically, the lowest temperature that occurred during the model development period (2014 – 9/2019) for the DEP analysis was 10 degrees, while the lowest temperature among the 39-year weather years was minus 3 degrees. The model development period (the neural net training period) did not have low temperature observations consistent with the low temperatures that occurred in some of the 39 weather years. This has an impact on the ability of the model to accurately simulate the 2024 loads for these weather years when such low temperatures occurred. To address this potential problem, Astrapé developed simple linear regression models to estimate the load impact at extreme low temperatures. The regression model (shown in Table 7) for DEP-East winter mornings consisted of using only 9 observations. The model was estimated using the same training period data base (2014 – 9/2019) as was used to develop the neural net model. This model had an R^2 of 0.70, which means the model only explained 70% of the variability in load as a function of temperature.

Table 7
DEP-East Cold Weather Load Regression

Regression Statistics	
Multiple R	0.835709908
R Square	0.698411051
Adjusted R Square	0.655326915
Standard Error	602.2688629
Observations	9

ANOVA

	df	*SS*	*MS*	*F*
Regression	1	5879962.286	5879962.286	16.21039953
Residual	7	2539094.482	362727.7832	
Total	8	8419056.768		

	Coefficients	*Standard Error*	*t Stat*	*P-value*
Intercept	17632.81072	1007.97699	17.4932671	4.91036E-07
Temp	-263.1854316	65.36796821	-4.026214044	0.005019851

It is important to recognize that, because the model specification is linear, it is assumed that load will continue to increase as temperatures drop. Since the model estimation period did not reflect any temperatures lower than 10 degrees, there was no information about the responsiveness of load to low temperature changes for temperatures below 10 degrees. Finally, in addition to the low temperature regression models, Astrapé also used a smoothing adjustment and a proprietary algorithm to produce the load shape in each of the 39 weather years.

ORS's review of the Company's analysis indicates that the approach used was not unreasonable, though we do have some concerns regarding the ability of the model to accurately measure the effect of extreme low temperatures on load and the impact that may have on the estimation of LOLE.

This issue has a significant impact on the level of required winter reserves needed to maintain an LOLE of 0.10. To examine this impact, ORS recalculated the LOLE analysis developed by the Company under two alternative scenarios: one in which 1982 weather is removed, and another in which both 1982 and 1985 weather are removed from the analysis. The purpose of this analysis is to develop an understanding of the importance of extreme cold weather years on the overall LOLE results, not to suggest or recommend that the LOLE analysis exclude these extreme weather years. The weather in 1982 and 1985 reflected very low winter temperatures. The lowest winter temperatures in the 39-year data base occurred in 1985 for DEP.

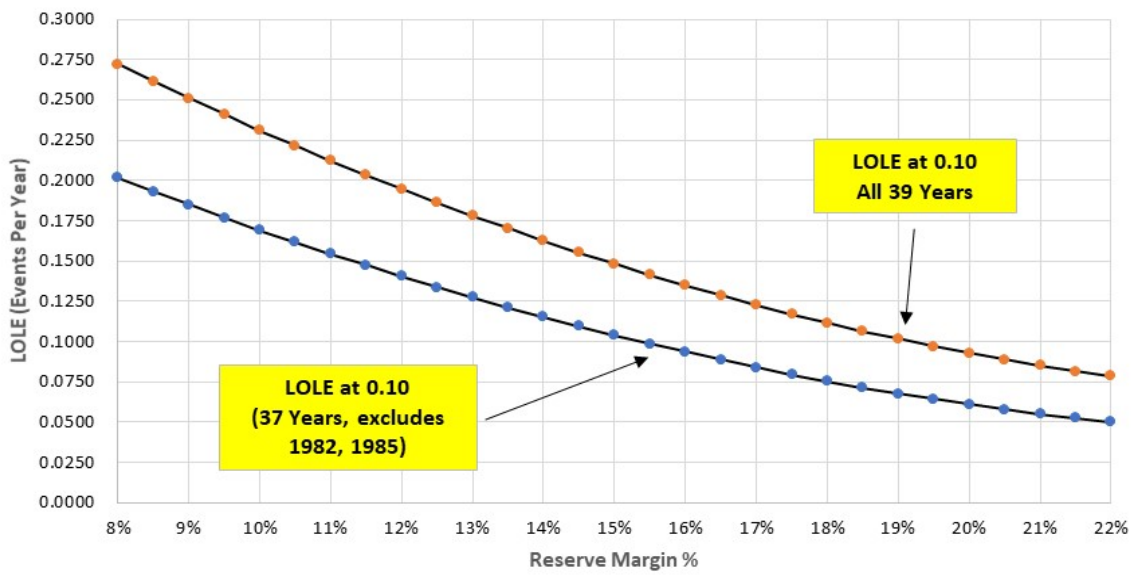
The results of this analysis indicate that the reserve margin required to achieve a 1 day in 10-year LOLE would drop significantly, based on the Company's methodology, if the 1982 and 1985 weather years were excluded from the evaluation. Table 8 below shows the results for DEP.

Table 8
DEP Reserve Margins vs. LOLE
Using Alternative Weather Years

	LOLE - Events Per Year		
Reserve Margin	**All Weather years**	**Weather years excluding 1982**	**Weather years excluding 1982, 1985**
8.0%	0.272	0.251	0.202
8.5%	0.261	0.240	0.193
9.0%	0.251	0.230	0.185
9.5%	0.241	0.220	0.177
10.0%	0.231	0.210	0.169
10.5%	0.222	0.200	0.162
11.0%	0.212	0.191	0.154
11.5%	0.203	0.182	0.147
12.0%	0.195	0.174	0.140
12.5%	0.186	0.166	0.134
13.0%	0.178	0.158	0.127
13.5%	0.170	0.150	0.121
14.0%	0.163	0.143	0.115
14.5%	0.155	0.136	0.109
15.0%	0.148	0.129	0.104
15.5%	0.141	0.123	0.099
16.0%	0.135	0.117	0.094
16.5%	0.129	0.112	0.089
17.0%	0.123	0.106	0.084
17.5%	0.117	0.101	0.080
18.0%	0.112	0.097	0.075
18.5%	0.106	0.092	0.071
19.0%	0.102	0.088	0.068
19.5%	0.097	0.085	0.064
20.0%	0.093	0.081	0.061
20.5%	0.089	0.078	0.058
21.0%	0.085	0.076	0.055
21.5%	0.082	0.073	0.052
22.0%	0.078	0.071	0.050

If 1982 weather alone is excluded, the 0.10 LOLE target is met at a winter reserve margin of 17.5%. If the LOLE analysis excludes both 1982 and 1985 weather, the 0.10 LOLE target is met at a winter reserve margin of 15.5%. Both of these reserve margin targets are significantly below the 19.25% winter peak reserve margin produced in the Astrapé study for DEP using a full 39-year weather data set. The ORS analysis demonstrates how sensitive the SERVM resource adequacy results are to just a couple of years of extreme low temperatures out of the full 39-year period. While ORS did not attempt to calculate the effect on the combined DEP/DEC reserve margin using only 37 years of weather data, it is likely that a similar reduction in the required winter peak reserves would be produced. Figure 3 provides a comparison of the LOLE curves based on the full 39 years of weather (1980 – 2018) and 37 years of weather (excluding weather for the years 1982 and 1985).

Figure 3
DEP Reserve Margin vs. LOLE
39 Years of Weather vs 37 Years of Weather
(excluding 1982, 1985 Weather Years)



ORS also reviewed other inputs in the LOLE analysis, including the neighboring utility tie-line support that is assumed to be available during emergencies. The SERVM analysis assumed emergency support from seven interconnected utilities and regions, not including support from DEC. The analysis developed 39-year load-weather relationships for each of these neighboring utilities so that the SERVM Monte Carlo analysis would measure the load diversity of these external sources under varying weather conditions. This is an attempt to reflect that fact that weather patterns tend to be regional. For example, during extreme cold weather on the DEP system or on the combined DEP/DEC system (which is actually used to set the reserve margin in this 2020 IRP), other neighboring utility systems may also experience extreme cold weather, limiting the availability of otherwise available emergency imports. The model attempts to portray such dependencies. The is a significant modeling enhancement, which would appear to increase the ability of the analysis to reflect likely events during extreme low temperatures.

ORS also examined the assumed probability distribution of load forecast errors ("LFE"). Normally, in these types of economic analyses, the probability distribution associated with load forecast errors is assumed to be symmetric – in other words, equal probabilities of an over-forecast and an under-forecast. In this case, pursuant to the Stakeholder process, the Company employed a non-symmetric probability distribution such that the likelihood of an over-forecast is greater than an under-forecast. Table 9 shows this load forecast probability distribution based on a four-year ahead forecast.

Table 9
SERVM Load Forecast Error

Assumed Forecast % Error*	Probability
95.80%	10%
97.30%	25%
100.00%	40%
102.00%	15%
103.10%	10%

* A % less than 100% has the effect of reducing the peak load forecast.

The load forecast error distribution is used in the Monte Carlo analysis to either reduce or increase the load forecast for each weather year. For example, based on the distribution, 10% of the time, the computed load forecast is assumed to be too low and would be increased by applying a factor of 103.10% to each load value. All else being equal, this has the effect of increasing the loss of load events in that scenario. While conceptually, the inclusion of LFE in an LOLE analysis is reasonable, the estimation of an LFE probability distribution is a potentially contentious issue. The Astrapé analysis derived the four-year ahead forecast errors from recent experience in economic forecast errors contained in the Congressional Budget Office forecast of Gross Domestic Product ("GDP"). While a GDP forecast error might be one of the components of a load forecast error for a utility it is not the only source of errors. Putting aside weather-related errors, which are separately reflected in the Company's LOLE analysis, there are additional sources of forecast errors beyond GDP or other measure of economic activity. Among these are the forecast modeling errors themselves. That is, the error in a forecast model predicting load, given know input factors such as weather and economic activity. This model related error has a probability distribution. As such, the usefulness of reflecting LFE in the resource adequacy analysis is questionable. Ironically, because the LFE probability distribution is weighted towards an assumed over-forecast, the inclusion of LFE in the Company's analysis actually resulted in a lower reserve margin, all else being equal.[41] However, using a symmetric LFE probability distribution in the analysis increased the reserve margin by 1% (19.25% to 20.25%).

The final resource adequacy issue that ORS reviewed was associated with other work that Astrapé performed that concerned the capacity value assumptions for standalone solar and solar plus battery storage resources. Astrapé derived capacity value assumptions based on similar modeling techniques using its SERVM model. These capacity values represent the percentage of installed nameplate capacity that contributes to meeting peak loads in the summer and winter. Since the winter peak drives the need for capacity on both the DEP and DEC systems, the winter capacity values of solar and solar plus battery are of the main importance.

The Company used a 1% winter capacity value for standalone solar and a winter capacity value of 25% for solar plus battery, based on an assumed 4-hour discharge assumption. These capacity values, which materially impact the economic value of solar, are based on two Astrapé analyses of the effective load carrying capacity ("ELCC") of various solar and solar plus battery technologies.[42] ORS has evaluated these two studies and has found them to be generally reasonable. They are both based on simulations using the SERVM model that is used to determine the Company's planning reserve margins. ORS is concerned that the IRP report (including appendices) did not discuss how the actual inputs into the Company's resource expansion plan modeling (the System Optimizer model) were derived from the capacity value summary results reported. For example, the standalone solar capacity values presented in the 2018 Astrapé ELCC study as part of the Company's avoided cost case (Docket No. 2019-186-E) were reported for various levels of solar capacity ("0", "existing plus transition", and 4 additional tranches comprised of either fixed or tilt solar technology), while for IRP planning purposes, a single 1% capacity value assumption was used for

[41] Astrape reported a sensitivity analysis wherein the LFE was removed. The resulting reserve margin required to meet a 0.10 LOLE increased in this "LFE removed" scenario.

[42] The solar capacity values are developed in a 2018 Astrapé report ("Duke Energy Carolinas and Duke Energy Progress Solar Capacity Value Study") and a 2020 Astrapé report that is included as an attachment to the IRP Report ("Attachment IV Duke Energy Carolinas and Duke Energy Progress Storage Effective Load Carrying Capability (ELCC) Study").

all assumed levels of solar capacity on the system. Given the potential significance of the assumed solar capacity values, ORS recommends the Company provide an explanation of the derivation of the actual planning model inputs.

Further discussion of the solar and solar plus battery capacity value results is included below in the Generic Resources section of this report.

Conclusions – Resource Adequacy – Reserve Margin Issues

Overall, ORS concludes that the Company's 17% winter peak reserve margin analysis meets the requirements of Act 62, is reasonable and represents a high level of methodological sophistication. The methodology used by the Company to develop its analysis, which uses the SERVM model to perform a Monte Carlo analysis that incorporates probability-based risk profiles for numerous factors that affect resource adequacy is also reasonable. A 17% winter peak reserve margin is generally consistent with the target winter peak reserve margins of a number of utilities in the Mid-Atlantic and Southeast areas. Table 10 below shows a compares the DEP/DEC winter peak reserve margin to those of a number of these utilities.

Table 10
Comparison of Utility Winter Peak Reserve Margins

Utility	Winter Peak Reserve Margin
DEP/DEC	17%
Dominion Energy South Carolina	21%
Southern Company	26%
TVA	25%
Louisville Gas and Electric/ Kentucky Utilities	17% to 25%
Florida Power and Light Co.	20%

Recommendations – Resource Adequacy – Reserve Margin Issues

2. We recommend the Company provide a more detailed discussion of the specific methodology used to develop the synthetic loads for extreme low temperature periods. While the Resource Adequacy Report provides an overview of this issue, it does not provide sufficient detail regarding how the analysis was conducted or what specific additional adjustments were made to the load data at extreme low temperatures. This detail was provided in response to discovery in this proceeding, however, we recommend this level of detail be included in future IRPs as part of a comprehensive technical appendix. **(L)**

3. We recommend the Company further develop its methodology to model the effects of extreme low temperatures on winter peak load. Given the significance of this issue, as discussed in the ORS Report, we would like the Company to examine alternative methodologies to develop its synthetic loads in hours in which the temperatures fall significantly below the temperatures experienced during the weather/load estimation period (i.e., neural net model training period). We recommend this be addressed in future IRPs through the Company's stakeholder process. **(L)**

4. We recommend the Company provide a detailed discussion in the IRP Report or appendices that explains how the results of the Astrapé 2018 Solar Capacity Value Study was used to derive the assumed winter peak standalone solar capacity value of 1%. We recommend this information be included in a modified IRP in this proceeding. **(N)**

Energy Efficiency and Demand Side Management

The Company's IRP includes both EE and DSM (DR) programs in its IRP analyses. Currently, the Company has 13 EE and 4 DSM offerings in the DEP territory that were available as of December 31, 2019.[43]

Specifically, the programs offered were:

Residential EE

- EE Appliances and Devices
- EE Education
- Multifamily EE
- My home energy report
- Neighborhood Energy Saver (Low-Income)
- Residential Energy Assessments
- Residential New Construction
- Residential Smart $aver EE

Non-Residential EE:

- Non-Residential Smart $aver EE Products and Assessment
- Non-Residential Smart $aver Performance Incentive
- Small Business Energy Saver

[43] DEP 2020 IRP pg. 237.

Combined Residential/Nonresidential EE:

- EE Lighting
- Distributed System Demand Response (DSDR)

Residential DSM:

- EnergyWise Home

Non-Residential DSM:

- CIG Demand Response Automation
- Large Load Curtailable Rates & Riders
- EnergyWise Business

For the IRP, the Company's base case energy savings projection was based partly on DEP's five year EE program plan for 2020-2024, and partly on results that were determined in an EE MPS that was performed by Nexant, Inc. ("Nexant") and that was completed in June 2020. The Company asserted that Nexant's results were suitable for use as a long range projection, however, the study did not "attempt to closely forecast short-term EE achievements from year to year."[44] Therefore, the Company developed the EE/DSM saving projections for the IRP by blending DEP's five-year program planning forecast into the long-term achievable potential projections from the market potential study.

Nexant's MPS study determined feasible (technical, economic and realistic achievable market potential) energy savings for EE programs over short term (5-year projection), medium term (10-year projection), and long term (25-year projection) periods. Nexant relied on its TEAPot (Technical, Economic, and Achievable Potential) model to calculate potential energy savings based on input assumptions that included sales/load forecasts that were disaggregated into customer-class and end use components, electricity prices, discount rates, historic program energy savings, fuel shares, current market saturation, and program costs. Nexant examined a range of commercially available EE measures by end-use.[45]

Nexant derived estimates of cumulative technical potential, which ignored program costs and focused strictly on energy savings, assuming that the energy savings would be technically feasible. Nexant determined that the upper limit for technical potential as a percentage of 2044 electricity sales would be approximately 33% in the DEP territory. Nexant evaluated the economic potential of EE programs using the Total Resource Cost ("TRC") test and found that all existing EE programs would continue to be

[44] DEP 2020 IRP, pg. 35.
[45] DEP 2020 IRP Attachment V, Nexant Duke Energy EE and DSM MPS, pg. 1.

economic based on the TRC test. Nexant also evaluated the achievable potential of EE programs based on the willingness of customers to participate and determined achievable energy savings would likely average approximately 0.81% of annual Base Sales in the DEP territory over the 25-year study period.[46]

Nexant developed projections of EE impacts over the 25-year study period for three energy savings scenarios, as follows:

- Base Scenario – consistent with existing EE program portfolio.
- Enhanced Scenario – Base Scenario plus increased program spending (via incentives) to attract an increased level of EE customer participation.
- Avoided Energy Cost Scenario – Base Scenario plus uses higher avoided energy costs resulting in higher valued EE programs. Potentially includes additional cost-effective measures and increased achievable potential.

The Company then blended Nexant's scenarios with its 5-year EE program plan for 2020-2024 to develop Base, High and Low EE scenarios that were used in the IRP, pursuant to Act 62 requirements. The Company developed the following three (3) forecasts:

- Base Case forecast – blends together DEP's five (5) year plan with Nexant's Base Achievable Portfolio. Residential savings average 1.5% of sales[47] in the 2021-2035 period.
- High Case forecast – incorporates impacts of both Nexant's Enhanced and Avoided Cost Sensitivity Scenarios. Yearly energy savings are between 4% and 11% higher than the Base Case for the 2021-2035 period.[48]
- Low Case forecast – impacts are assumed to be 75% of the Base Case.

The Base Case forecast was derived by using the Company's five (5) year plan for the 2020-2024 period, then by blending five (5) year plan and the MPS for the 2025-2029 period, and then finally using the MPS for the 2030-2035 period.

The Company indicates that future DSM efforts will be focused on reducing winter peak demand. This appears to be a reasonable decision as the majority of current DSM efforts are focused on summer peak reduction.

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[46] *Id*. pg. 2
[47] North Carolina Public Staff (NCPS") Data Request ("DR") 2-17.
[48] DEP 2020 IRP, p. 261-263.

ACEEE conducts yearly evaluations of statewide EE efforts, and ranks states against each other on a variety of metrics. The percentage reduction in retail energy sales is one such metric. Though the ACEEE State Energy Efficiency Scorecard compares statewide efforts, it is a useful benchmark for comparing program success across the country. The Company's projected 1.5% of sales savings would be given a score of 5 of a possible 7 in ACEEE's 2019 report, scoring in the top quartile, which is a reasonably high ranking.[49]

The Commission approved the Company's most recent five-year DSM and EE Program plan in its order on January 15, 2021, which has a goal of achieving energy savings of 1% of annual retail sales.[50] Per the IRP forecast, the Company is poised to exceed its 1% of retail energy sales savings goal.

The Company's EE sensitivity analysis indicated that the high EE case would be even more economic than the base case, but by just a small amount, 1.8%.[51] The Company believes "executability risks" of being able to achieve the high level of EE savings outweigh the potential savings, and therefore it did not include the High EE case as part of its Base Case plan.[52]

ORS notes that the Company did not explain its concern with executability risks, and also it did not fully evaluate fuel cost risk in its EE sensitivity evaluation. In that sensitivity case, the Company strictly compared a case with its base assumptions (including base fuel cost assumptions) to a base case that incorporated the high EE forecast assumptions. However, the Company did not assess the impact of the high or low EE forecasts under different fuel and CO_2 cost assumptions. ORS recommends the Company provide additional EE cases examining different levels of fuel and CO_2 prices, both high and low.

Finally, the Low DSM/EE case is assumed to be 75% of the base case. It is not clear how this scale factor was chosen. ORS recommends that the Company provide additional detail regarding this figure and explain why the Company believes it represents a reasonable lower band estimate.

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[49] https://www.aceee.org/sites/default/files/publications/researchreports/u1908.pdf, p.39.

[50] *Application of Duke Energy Progress, LLC to Establish a New Cost Recovery and Incentive Mechanism for Demand-Side Management and Energy Efficiency Programs, Docket 2015-163-E, Order Issued January 15, 2021 (Order No. 2021-33).*

[51] DEP 2020 IRP pg. 168. Table A-9. See "High EE" row.

[52] DEP 2020 IRP p. 170.

Recommendations – Energy Efficiency and Demand Side Management

5. ORS recommends the Company provide additional justification for selecting the Base EE/DSM case as opposed to the High EE/DSM case for use in Portfolio A, given that the High EE/DSM case may provide greater customer benefits. We recommend this information be included in a modified IRP in this proceeding. **(N)**

6. ORS recommends that in addition to the sensitivity cases included in Table A-9, the Company also evaluate high and low levels of EE/DSM using high fuel/CO_2 and low fuel/CO_2 assumptions. We recommend this information be included in a modified IRP in this proceeding. **(N)**

7. The Company provided no basis for the low EE/DSM forecast that it used in the IRP. The Company's approach may be reasonable; however, it would be a better practice to provide more justification as to how it derived the low EE/DSM forecast. ORS recommends the Company provide additional justification or consider other approaches for deriving the low EE/DSM forecast. We recommend this be addressed in future IRPs through the Company's stakeholder process. **(L)**

Natural Gas Price Forecasts

The Company developed three natural gas price forecasts, including a low, base, and high forecast. The Company developed these forecasts using a method that blended together a market-based forecast with a fundamentals-based forecast. The Company used market-based pricing for its 2021-2030 forecasts, and it gradually transitioned that to a 100% fundamental based forecast by 2035 and beyond.[53]

The market-based forecast came from a [redacted] which the Company used as its market assumptions for 2020-2030. Beginning in 2031, [redacted] which was referred to as the North American Natural Gas Long-Term Outlook, February 2020. By 2035, the forecast was completely based on the [redacted] fundamentals forecast.[54]

To derive high and low forecasts, the Company determined the implied volatility within the gas strip and used that to project 90th and 10th percentile estimates, which it used as its high and low market-based forecasts. [redacted]

[53] DEP 2020 IRP pg. 157.
[54] ORS DR 2-3a.

[redacted][55]

The following three graphs compare the Company's low, base and high gas price forecasts to other recent utility and industry forecasts that are publicly available and have been released since December 2019. ORS has computed "consensus forecasts" by averaging the publicly available forecasts each year, including DEP's natural gas price forecasts. The other utility forecasts were from relatively recent IRPs, including Kentucky Power,[56] Xcel Upper Midwest,[57] DESC,[58] Virginia Power,[59] DTE Electric,[60] Avista,[61] and Tucson Electric.[62] In addition, EIA[63] forecasts were also included, with EIA's High Oil and Gas Supply forecast included in the low consensus forecast, EIA's Reference Case in the base consensus forecast, and EIA's Low Oil and Gas Supply in the high consensus forecast.

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[55] *Id.*
[56] Kentucky Power 2019 Integrated Resource Planning Report, p. 78. https://psc.ky.gov/pscecf/2019-00443/sebishop%40aep.com/12202019120748/KPCO_2019_IRP_Volume_A_Public_Version.pdf
[57] Excel Energy 2019 Upper Midwest Intergrated Resource Plan; Figure 2-10. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7BF0AB0573-0000-C11C-B7B2-2FA960B89BD1%7D&documentTitle=20206-164371-01
[58] DESC 2020 IRP, Docket No. 2019-226-E, ORS AIR 2-3. .
[59] Virginia Power 2020 IRP; Appendix 4O; page 4. https://www.dominionenergy.com/-/media/pdfs/global/2020-va-integrated-resource-plan.pdf?la=en&rev=fca793dd8eae4ebea4ee42f5642c9509
[60] DTE Electric Company 2019 IRP; Appendix S; Exhibit 11. https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000006YILTAA0
[61] Natural Gas IRP; TAC 4: Wesnesday November 18,2020; p.87. https://www.myavista.com/about-us/integrated-resource-planning
[62] Tucson Electric Power Company; 2020 Integrated Resource Plan; Chart 32. https://www.tep.com/wp-content/uploads/TEP-2020-Integrated-Resource-Plan-Lo-Res.pdf
[63] Annual Energy Outlook 2020; Table 13. Natural Gas Supply, Disposition, and Prices. https://www.eia.gov/outlooks/aeo/data/browser/#/?id=13-AEO2020&region=0-0&cases=ref2020~highogs~lowogs&start=2018&end=2050&f=A&linechart=~~~~~~~~~ref2020-d112119a.60-13-AEO2020~highogs-d112619a.60-13-AEO2020~lowogs-d112619a.60-13-AEO2020&map=&ctype=linechart&sourcekey=0

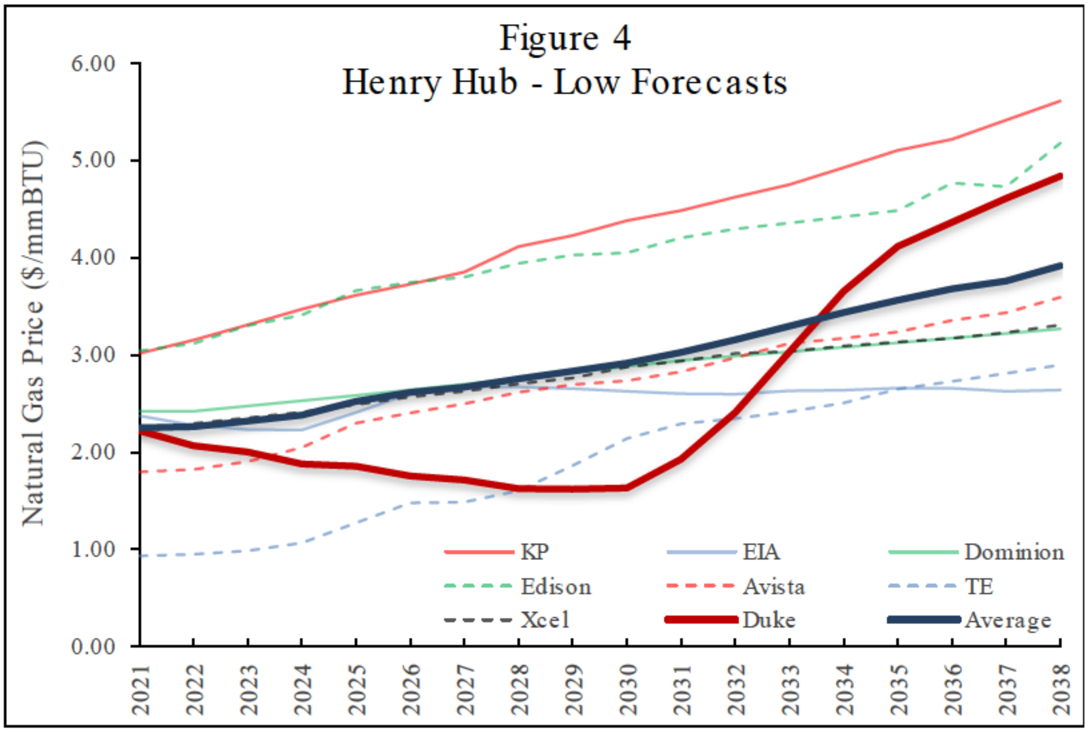
Figure 4
Henry Hub - Low Forecasts
Natural Gas Price ($/mmBTU)
6.00
5.00
4.00
3.00
2.00
1.00
0.00
KP
EIA
Dominion
Edison
Avista
TE
Xcel
Duke
Average
2021
2022
2023
2024
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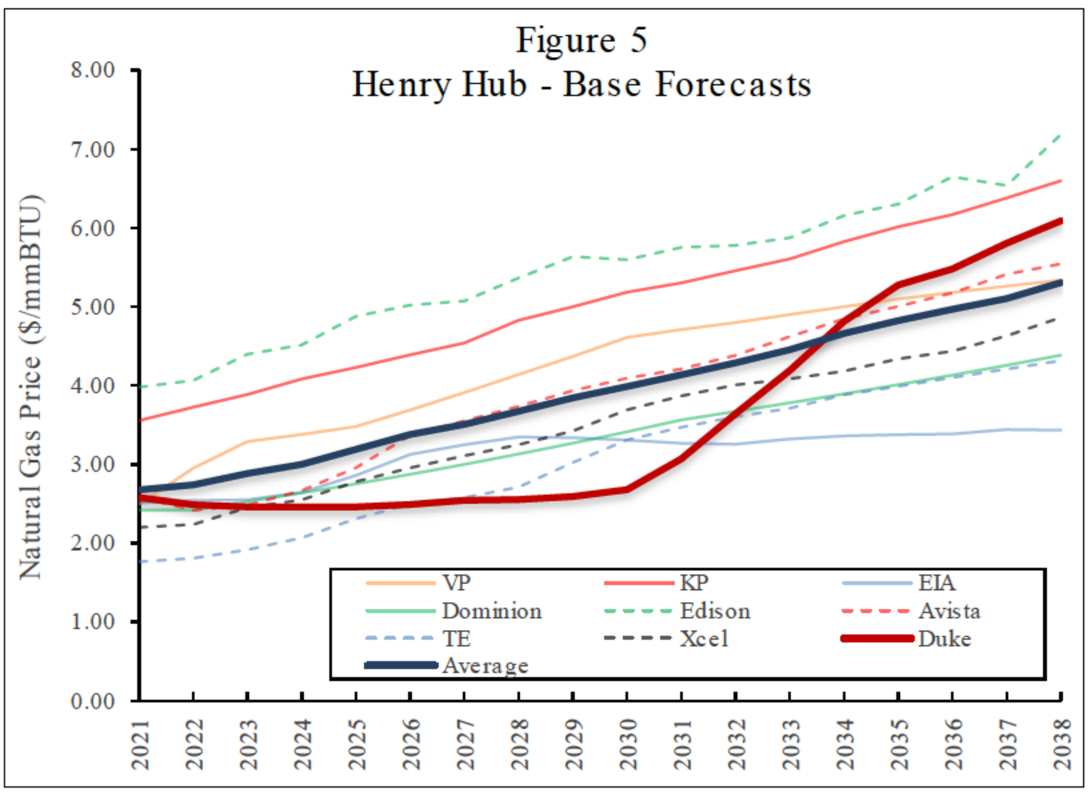
Figure 5
Henry Hub - Base Forecasts
Natural Gas Price ($/mmBTU)
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
VP
KP
EIA
Dominion
Edison
Avista
TE
Xcel
Duke
Average
2021
2022
2023
2024
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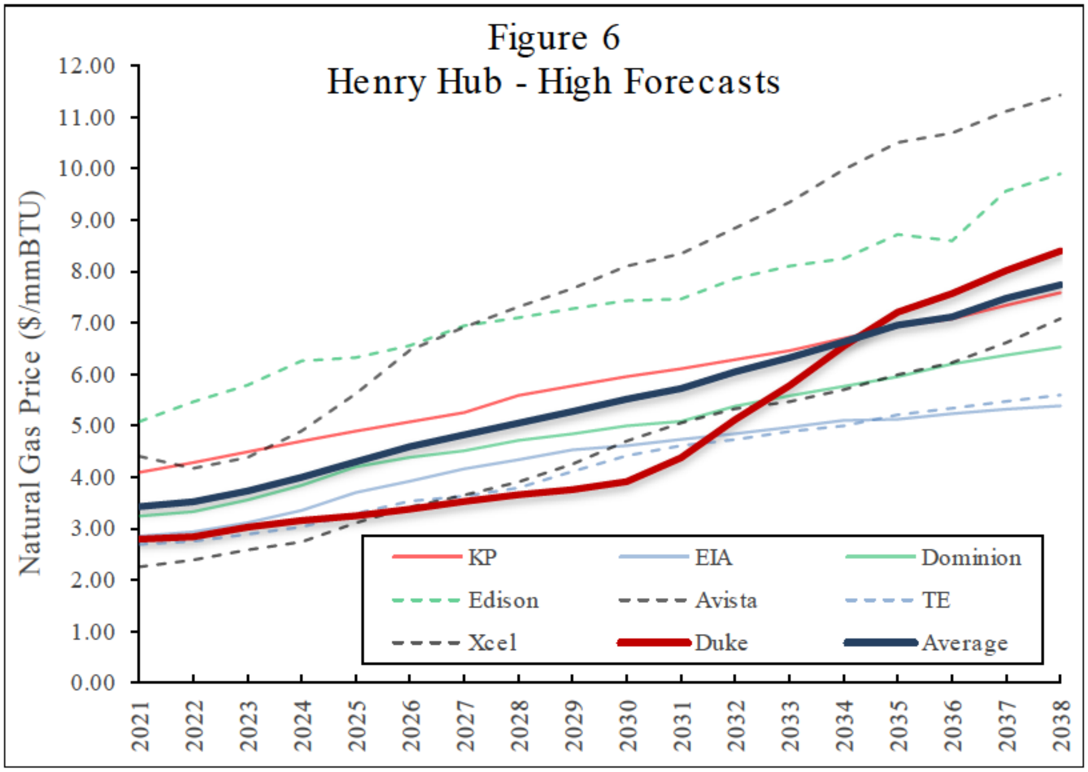
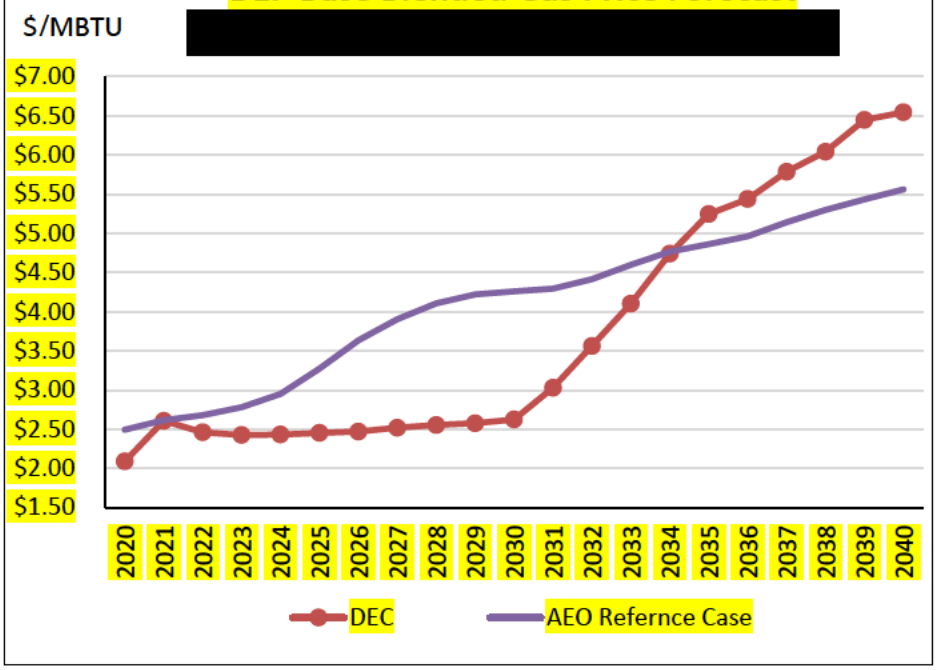


Figure 6
Henry Hub - High Forecasts

The Company's natural gas price forecasts are consistently lower than the consensus forecasts in all three (3) cases by a small amount over the period of 2021 to about 2035. After that the DEP forecast actually exceeds the consensus forecast by a small amount in all three (3) cases. ORS recognizes that the future is unknown and that natural gas price forecasts have been lowered considerably over the last ten years. While DEP's forecasts do appear to be a little low over the planning horizon, the important question is whether DEP's forecasts are outliers when compared to the other forecasts, and the answer is no. Some of the other comparable forecasts are actually lower or are close to DEP's forecast over the planning horizon.

While DEP's forecasts do not appear to be unreasonable, there may be an opportunity for improvement. The development of the Company's base gas price forecast is illustrated in the following graph, which shows that the DEP Base forecast is equivalent to the market forecast (NYMEX) until 2030, then trends into the fundamental forecast ([redacted]) until 2035, and follows the fundamental forecast thereafter.

Figure 7
DEP Base Blended Gas Price Forecast



There are a few noticeable issues regarding the Company's forecast including the fact that it is rather flat for about ten years. The Company appears confident that based on actual market quotes it can lock in its gas supply for its entire system for the next ten years, which in our experience would be unusual for an electric utility to do. Second, even the Company's own fuel forecast vendor and EIA appear to have a different view of how natural gas prices will increase over time, and those two forecasts are largely consistent.

We point these concerns out because low gas price forecasts could result in indicating that natural gas-fired resources are comparatively less expensive than they otherwise would be relative to other resource alternatives. As an example, assuming a combined cycle unit has a 6.5 million British Thermal Units (MBTU)/MWh average heat rate, the dispatch price of that unit in 2030, when comparing the Company's gas price forecast estimate to the EIA AEO estimate, would be $17.06/MWh versus $27.68/MWh, respectively, which amounts to over a 60% difference in dispatch price, which certainly would favor gas-fired resources.

The Company discusses its natural gas supply outlook in detail in Appendix F,[64] in which it notes that a decline in the production of natural gas occurred over the course

[64] DEP 2020 IRP pg. 300.

of 2020 and it is expected to continue into 2021 partly due to the economic slowdown caused by COVID-19. This is consistent with the Company's low price forecast over the short-term, but it does not necessarily mean that prices will continue to remain flat for the next ten years. The Company discusses that 5 and 10-year observable market curves are at $2.39 and $2.53, which is consistent with the Company's base forecast, however, as discussed above, it is not clear that the Company would or even could in fact lock in its entire gas supply for the next ten years.

In Appendix F, the Company also discusses its need for "additional upstream firm interstate transportation service to support existing and future natural gas generation."[65] With the cancellation of the Atlantic Coast Pipeline ("ACP") in July 2020, the Company has no active projects to expand its interstate gas supply. Without the ACP, the Company notes it will not have any direct access to Marcellus and Utica shale basins of West Virginia, Pennsylvania, and Ohio natural gas supply. The Company also noted that it will still need additional upstream firm interstate transportation service to support existing and future gas generation despite the cancellation of the ACP. For purposes of the IRP, the Company assumes that incremental firm transportation service would be obtained but from other suppliers than the ACP, and associated pipeline costs were modeled in the IRP. For example, the Company assumed that for each new CCGT modeled, firm inter- and intra-state transportation service would cost $114 million per year. The Company assumed that non-firm service (just intrastate) would be needed for new CTs at a cost of $4 million per year.[66]

<u>Recommendations - Natural Gas Price Forecasts</u>

8. ORS recommends the Company review its natural gas price forecasting methodology and investigate alternative approaches. We recommend this be addressed in future IRPs through the Company's stakeholder process. **(L)**

CO_2 and Other Environmental Issues

In Chapter 16 entitled, Sustaining the Trajectory to Reach Net-Zero, the Company discusses its corporate sustainability goals, which it states were set in 2019 calling for a reduction in CO_2 emissions by at least 50% from 2005 levels by 2030, and to achieve net-zero CO_2 emissions by 2050. The Company notes that DEP and DEC have already made considerable progress as they have reduced emissions by 38%, which exceeds the industry average of 33%.

[65] *Id.* pg. 304.
[66] NCPS DR 3-26.

The Company explains that the path forward to being able to meet its carbon objectives will require actions that it as well as others will have to take, including:

- Investing in the grid to allow growth in renewables and energy storage and to implement intelligent grid controls,
- Developing proper planning tools to study dynamic impacts to leverage energy storage and customer programs such as rooftop solar and EV charging,
- Continuing to implement EE and DSM,
- Relying on natural gas as a bridge to renewables,
- Advancing clean technologies such as small modular nuclear reactors,
- Continuing to operate its nuclear fleet, which will require license renewals, and,
- Establishing supportive policies that would lead to CO_2 reductions.

As mentioned, the Company believes that natural gas will play an important role in helping to reduce emissions over time and maintain affordable costs, as it states:

> In adding roughly equivalent amounts of natural gas combined cycle and solar generation, the ability of natural gas combined cycle generation to displace the coal generation at much higher capacity factors drove the significantly larger portion of the 38% carbon reduction while keeping customer costs low. Finding the right balance between accelerating the pace of emissions reductions and new technology deployment while maintaining affordability for customers will continue to be an important consideration moving forward.[67]

To address stakeholder concerns about the potential impact that adding natural gas units could have on customer costs if those assets are ultimately retired early, the Company performed a sensitivity analysis in which it modeled natural gas resources (CTs and CCGTs) with a shortened operating life of 25 years. The Company found that the optimization model still selected natural gas units economically.[68]

With regard to the bulleted item above concerning the need for supportive policies, the Company asserts that unless federal and or state CO_2 policies are implemented, the Company's CO_2 emissions would not likely exceed a 55% reduction and could actually

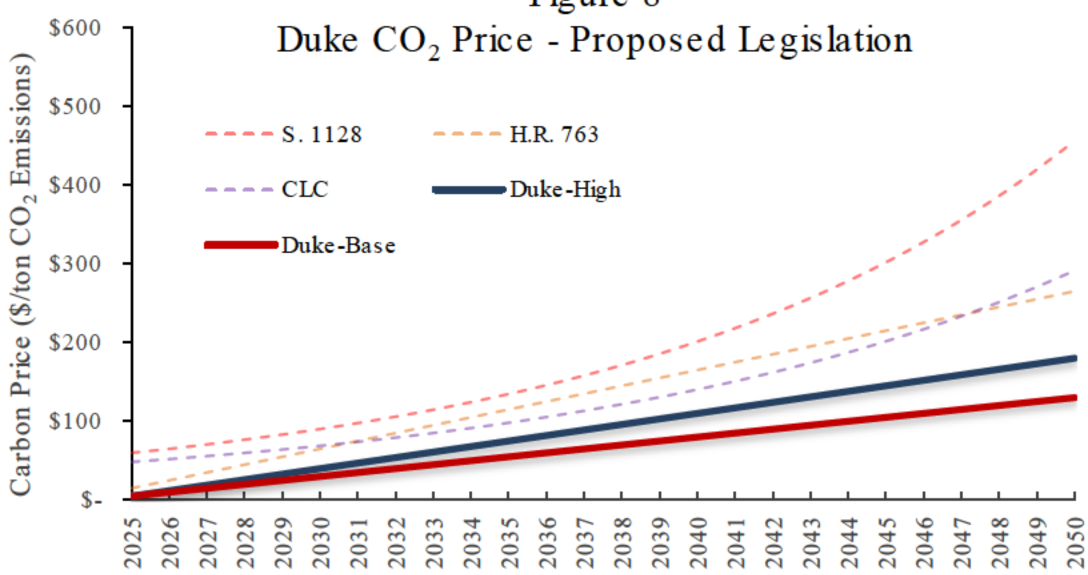
[67] DEP 2020 IRP, pg. 136.
[68] *Id.*

begin to increase once again, as demonstrated by results determined in the Company's Base Case without CO_2 portfolio.[69]

The Company also notes that supportive policies will be required to accelerate research, development and deployment of advanced technologies, to address interconnection issues, including interconnection queue reform, interconnection related transmission and distribution upgrades, transmission right-of-way acquisition, permitting, regulatory approval processes, and others.

In light of the above discussion, it is reasonable that although no federal or state CO_2 policies have been implemented to date, the Company has modeled CO_2 price sensitivity cases in the IRP, including a base CO_2 case of \$5/ton beginning in 2025 that grows by \$5/ton per year, and a high CO_2 case of \$5/ton beginning in 2025 that grows by \$7/ton per year. In addition to those, the Company also evaluated \$0/ton CO_2 cases as well. ORS examined the reasonableness of the Company's CO_2 assumptions by comparing them to other CO_2 forecasts that are publicly available such as from recently proposed legislation, EIA, and other utilities. The graphs below illustrate how the Company's forecasts compare, when compared to legislative proposals, EIA, and other utilities.

Figure 8
Duke CO_2 Price - Proposed Legislation



A brief description of the proposals in the graph are:

[69] DEP 2020 IRP, pg. 17.

- The Climate Leadership Council states that it attempts to develop consensus climate solutions in a bipartisan way. The Council's plan, as depicted above, starts at $40/Ton (2017$) and increases at 5% above inflation each year. Its goal is to reduce CO_2 by 50% from 2005 levels by 2035.[70]

- The Energy Innovation and Carbon Dividend Act (H.R. 763) was introduced in the U.S. House of Representatives on January 24, 2019 as another bipartisan attempt to address carbon emission issues.[71] This proposal starts at $15/Ton and increases at $10/Ton per year ($15/Ton if targets are not met), and the fee stops increasing if emissions decline by 90% compared to 2016 levels. The objective of the bill was to reduce emissions by approximately 40% by about 2030.

- The American Opportunity Carbon Free Act of 2019 (S. 1128)[72] was introduced into the senate by two Senators on January 24, 2019. The legislation would impose a tax starting at $52/Ton and would rise at 6% above inflation each year. By 2035, the emissions are projected to be about 50% below the 2005 emission level.

- Duke Energy's 2020 Base Case forecast begins at $5/Ton in 2025 and escalates at $5/Ton each year.

- Duke Energy's 2020 High CO_2 price forecast begins at $5/Ton in 2025 and escalates at $7/Ton each year.

From the Figure above, the Company's two proposals track reasonably well with the other proposals until around 2030 to 2035, though they are still lower than the legislative proposals during that period. To date, none of the legislative proposals have gotten much traction; however, that could conceivably change under the Biden administration with the new composition of Congress.

The following figure compares Duke Energy's forecasts to EIA projections and shows that Duke Energy's forecasts are reasonably consistent with EIA's.[73]

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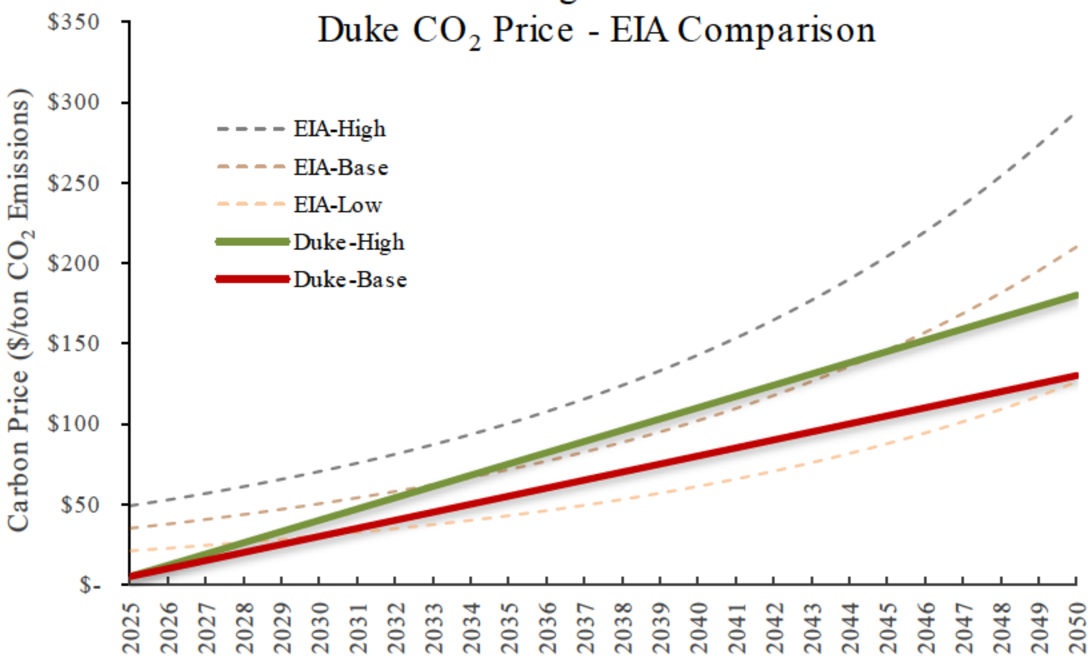
[70] https://clcouncil.org/Bipartisan-Climate-Roadmap.pdf.https://clcouncil.org/Bipartisan-Climate-Roadmap.pdf. Baker and Shultz are James Baker and George Shultz, both former republican Secretaries of State.

[71] https://www.congress.gov/bill/116th-congress/house-bill/763/text https://www.congress.gov/bill/116th-congress/house-bill/763/text

[72] https://www.congress.gov/bill/116th-congress/senate-bill/1128/text https://www.congress.gov/bill/116th-congress/senate-bill/1128/text

[73] EIA Altenative Policies March 2020, p 16. https://www.eia.gov/outlooks/aeo/pdf/AEO2020_IIF_Alternative_Policies_FullReport.pdf

Figure 9
Duke CO_2 Price - EIA Comparison



The following figure compares Duke Energy's Base CO_2 forecast to other publicly available base CO_2 utility forecasts and shows that Duke Energy's forecasts are also reasonably consistent with those forecasts, though in fact, Duke Energy's forecast is higher than the average of the forecasts. The other utility forecasts include PacifiCorp,[74] DESC,[75] Xcel Energy,[76] DTE Electric,[77] Virginia Power,[78] and Kentucky Power,[79] and the average of each forecast (including Duke Energy's).

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[74] Pacificorp 2019 IRP; Chapter 7 – Figure 7.3 CO2 Prices, https://pscdocs.utah.gov/electric/19docs/1903502/310626Chapter7Figure7.3CO2Prices10-25-2019.xlsx

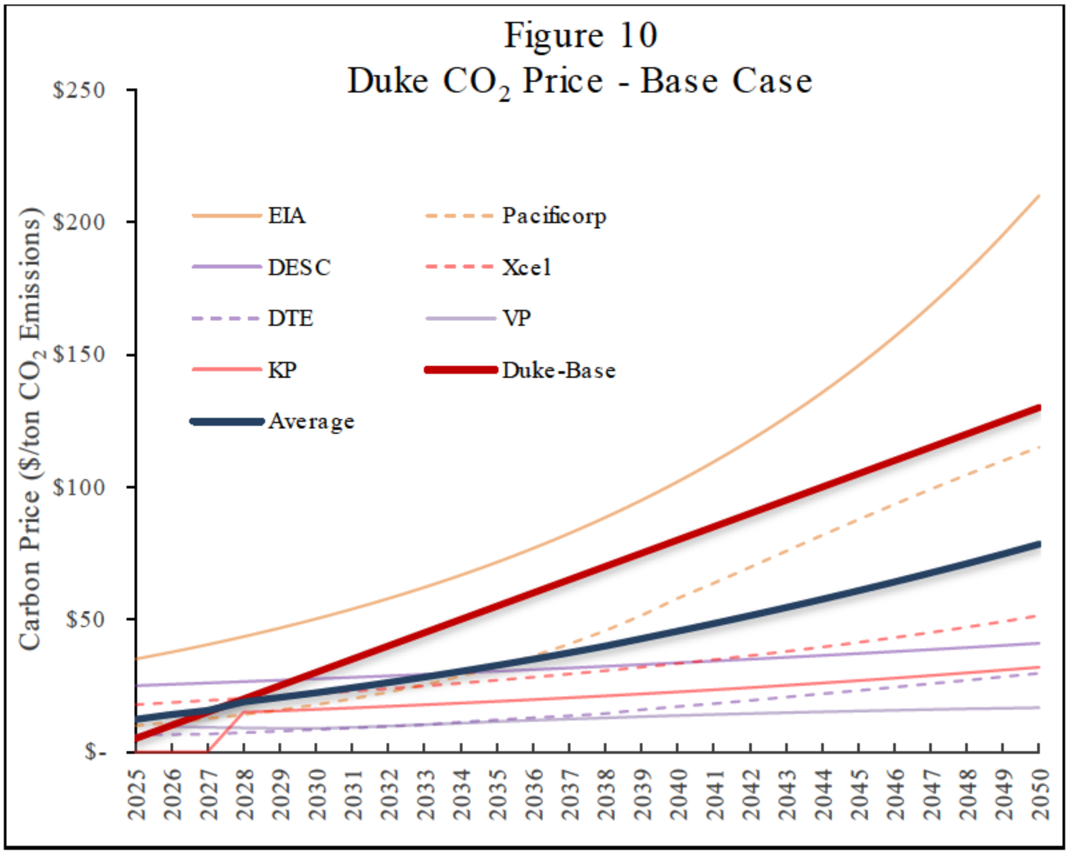
[75] DESC 2020 IRP, pg.44.

[76] Appendix F2: Strategist Modeling Assumptions & Inputs, pg. 3; Xcel Energy 2020-2034 Upper Midwest Resource Plan. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={00FBAE6B-0000-C414-89F0-2FD05A36F568}&documentTitle=20197-154051-01

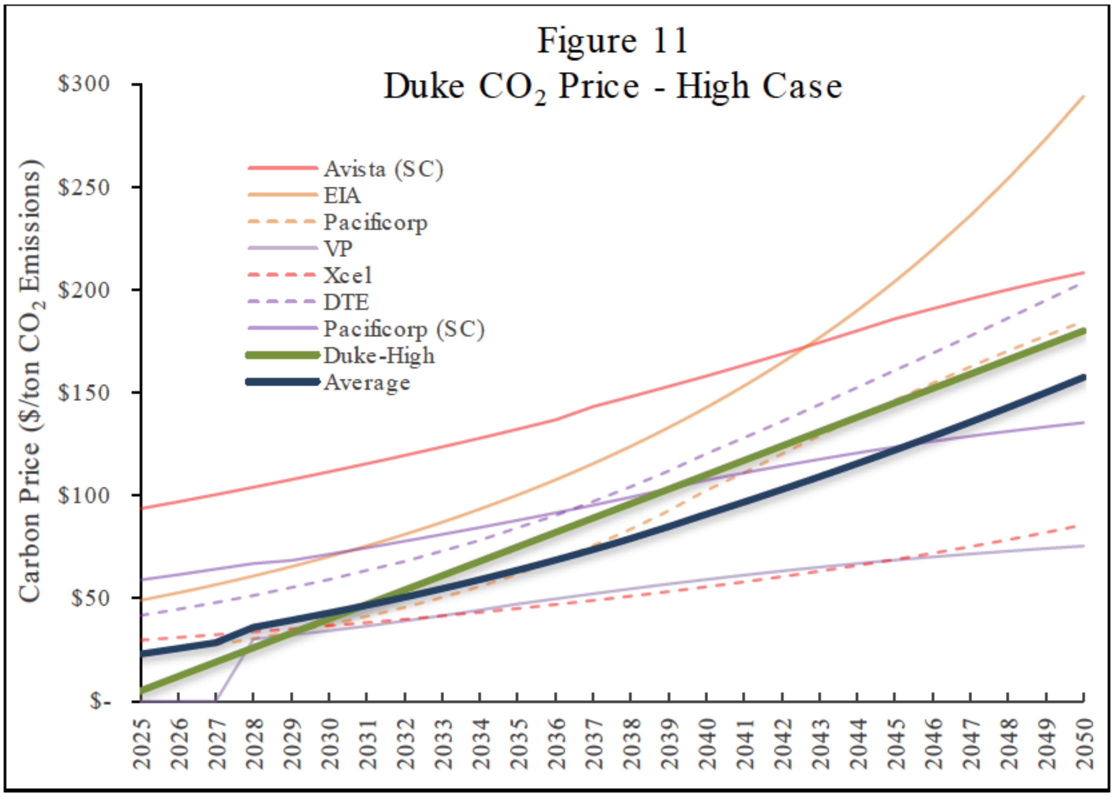
[77] DTE Electric Company 2019 IRP, Introduction, Figure 4.4.2, p. 26. https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000006YlLTAA0

[78] ICF Commodity Forecast: CO2, Appendix 4O, Virginia Electric and Power Company's 2020 Integrated Resource Plan. https://www.dominionenergy.com/-/media/pdfs/global/2020-va-integrated-resource-plan.pdf?la=en&rev=fca793dd8eae4ebea4ee42f5642c9509

[79] Kentucky Power 2019 Integrated Resource Planning Report, Significant Changes from 2016 IRP, pg. 5; https://psc.ky.gov/pscecf/2019-00443/sebishop%40aep.com/12202019120748/KPCO_2019_IRP_Volume_A_Public_Version.pdf



Lastly, the following figure compares Duke Energy's High CO_2 forecast to the other publicly available high CO_2 utility forecasts and shows that Duke Energy's forecast is once again reasonably consistent with the other forecasts, though in fact, Duke Energy's forecast is higher than the average of the forecasts.



Other Environmental Issues

In addition to planning for meeting its own corporate carbon reduction goals, there are a number of environmental regulations at the Federal and State level that the Company is required to meet. DEP discusses each regulation in Appendix I of the IRP, entitled Environmental Compliance. The regulations include:

Air Quality

- Acid Rain Program – Resulted in significant reductions in SO_2 and NO_x since about 2000. In compliance.
- Cross-State Air Pollution Rule ("CSAPR") – Must meet state emission limits for SO_2 and NOx on an annual basis. In Compliance.
- Mercury and Air Toxics Standards ("MATS") – Requires emission limits for hazardous air pollutants ("HAP"). Fully In compliance.
- 2002 North Carolina Clean Smokestacks Act ("NC CSA").
- 8-Hour Ozone National Ambient Air Quality Standards ("NAAQS") – Fully in attainment.
- SO_2 NAAQS – Fully in attainment.

- Fine Particulate Matter ($PM_{2.5}$) NAAQS – Fully in attainment.
- Greenhouse Gas New Source Performance Standards ("NSPS") – EPA established CO_2 limits for new coal and CCGT units built after 2014. These limits have no effect on DEP as its new CCGT units meet the requirements, and it is not proposing any new coal units.
- CO_2 Regulations Existing Coal and Natural Gas Units – Clean Power Plan ("CPP") rule finalized, then repealed. Affordable Clean Energy ("ACE") Rule created as replacement, however, now vacated, and new EPA rulemaking to take place.

Water Quality and By-Products

- Cooling Water Act 316(B) Cooling Water Intake Structures – Fish Impingement and entrainment. DEP expects the state to determine necessary entrainment controls for affected units in the 2020 – 2023 time period and intake modifications, if necessary, in the 2022 – 2026 time period.
- Steam Electric Effluent Limitation Guidelines ("ELG") – Prohibits discharge of bottom and fly ash transport water, flue gas mercury control wastewater, and establishes limits on discharge of wastewater from Flue Gas Desulfurization ("FGD") systems, and leachate from coal combustion residual landfills and impoundments. In 2019, the EPA remanded a part of the ELG rule to reconsider "legacy" wastewater and combustion residual leachate from landfills or settling ponds.
- Coal Combustion Residuals ("CCR") – Applies to all new and existing landfills, surface impoundments and it appears the Company has to close and remove CCR at all of its remaining surface impoundments.[80]

While the Company summarizes these regulations in the IRP Report, it does not include any discussions of the actual costs it anticipates it will have to spend to comply with these regulations or the costs that could potentially be avoided by retiring coal units early. That is not to say that DEP does not include these costs in its economic evaluations, in fact it does. However, ORS recommends that DEP provide additional tables that summarize the capital and O&M costs for environmental compliance by unit and by environmental regulation and include descriptions explaining those costs.

Recommendations - CO_2 and Other Environmental Issues

[80] DEP 2020 IRP pg. 359.

9. ORS recommends the Company provide tables summarizing the capital and O&M costs for compliance with environmental regulations by unit and by environmental regulation, and include descriptions explaining those costs. We recommend this information be included in a modified IRP in this proceeding. **(N)**

Existing System Resources

The Company has a diverse fleet of generating units consisting of nuclear, coal, CCGT, CT, hydroelectric, solar, and battery energy storage resources. Table 10 provides a list of the Company's resources, including the probable retirement dates and the nameplate capacity of each resource based on both the winter and summer ratings.

Table 11[81]

Station	Winter (MW)	Summer (MW)	Economic Retirement Date
Nuclear Total	**3,730**	**3,593**	
Brunswick	1,928	1870	2056
Harris	1,009	964	2066
Robinson	793	759	2051
Coal Total	**3,208**	**3,166**	
Mayo	746	727	2028
Roxboro	2,462	2439	2027 - 2028
Combined Cycle Total	**3,588**	**3,054**	
Asheville CC 1x1	560	474	2054
Lee CC 1 3x1	1,059	888	2054
Richmond/Smith CC 4 2x1	1,250	1085	2042 - 2051
Sutton CC 1 2x1	719	607	2055
Combustion Turbine Total	**3,440**	**2,834**	
Asheville	370	320	2039
Blewett	68	52	2025
Sutton	98	78	2053
Darlington	780	631	2021
Richmond/Smith	985	772	2041
Wayne	975	857	2040
Weatherspoon	164	124	2025
Hydro Total	**227**	**227**	
Blewett Hydro	27	27	
Marshall Hydro	4	4	

[81] DEP 2020 IRP Appendix B, p. 200.

Tillery Hydro	84	84	
Walters Hydro	112	112	
Energy Storage Total	**9**	**9**	
Asheville-Rock Hill	9	9	
[redacted]	[redacted]	[redacted]	
DSM Total[82]	**282**	**716**	
[redacted]	[redacted]	[redacted]	
Total Generating Capacity	**19,578**	**18,693**	

It is ORS's position that the PROSYM data is an important source of information for analysis purposes and relied on PROSYM data to create the table above. However, ORS encountered some difficulty in comparing different sources of information, as some of the PROSYM information differed when compared to other sources. For example, some of the PROSYM information was not identical to data found in the Company's Load, Capacity and Reserves table LCR, which contains the peak load projection, capacity data associated with existing and new resources, and the reserve margin calculation. ORS recommends that the Company confirm that there are no inconsistencies in the modeling data. To do this, ORS recommends the Company create a cross reference table that compares each resource modeled in PROSYM, including generating units, demand response, purchase contracts, sales contracts, EE, etc. to the corresponding data in the LCR table, on a resource by resource basis. We recommend this be developed for both the Base Case with CO_2 and Base Case without CO_2 cases and cover all of the years in the study period. Also, see the Renewables section of this report below for further discussion of this issue.

<u>New Planned Additions and Uprates</u>

The Company has included in its IRP database, projects that are underway, which it also refers to as "designated projects." These projects include:[83]

- Nuclear uprates – Brunswick 1&2 units will each receive 4-6 MW uprates, from 2024-2029. There will be a total of 20 MW of Winter Capacity Uprates through 2029.

<u>Relicensing</u>

The Company is planning to relicense all eleven (11) of its nuclear resources when each unit's current Nuclear Regulatory Commission ("NRC") issued operating license

[82] DEP 2020 IRP Report, Appendix D
[83] List of uprates in DEP 2020 IRP Report at pg. 210.

expires, which will extend each unit's life by ten (10) years and will ultimately result in each unit operating for a total of 80 years. The Company first announced its relicensing plans in September 2019, when it explained that it will be required to submit NRC Subsequent License Renewal ("SLR") applications for each unit.[84] The SLR process could take up to 5 years to prepare, and to go through the review and approval process. The DEC Oconee SLR application will be submitted first, beginning in 2021 and its licenses will expire in 2034 and 2035. While Duke Energy plans to relicense DEC's Oconee plant first, DEP's Robinson unit's operating license will actually expire earlier in 2030.

Given the impact of Duke Energy's nuclear fleet on both Companies' operations, ORS seeks additional details to be included in future IRPs regarding the Company's relicensing plans. ORS recommends that the Company supply a timeline outlining its schedule for relicensing all of its nuclear units, discuss costs it anticipates will be incurred to relicense the units, and provide details of its plans to conduct economic evaluations to assess the benefits of relicensing the units. ORS also recommend the Company provide additional insight into why it is beginning this process so far in advance of the relicensing dates for the Oconee units given that it may only take 5 year to relicense the units, and why the Robinson unit, despite its earlier license expiration date, is seeking relicensing later than the Oconee units.

Retirement of Coal Units

An important component of an IRP and a specific requirement of Act 62 is that utilities must develop portfolios to fairly evaluate retirements of existing resources, such as early retirements of coal units, particularly as the utilization of those resources diminishes over time. The Company conducted a detailed coal retirement analysis in this IRP based on a three-step process:[85]

Step 1 Ranking - Coal units were ranked in order of the best potential retirement candidate to the worst recognizing that after one unit retires the benefit of retiring the next diminishes and retirements should be studied based on an iterative process. For this ranking, the Company considered age, expected capacity factor, and capacity size of the units.

Step 2 SPM – This step was designed to determine the Company's optimal retirement dates. The SPM required running PROSYM using a base case with the studied unit

[84] IRP p. 76 and 122 and https://news.duke-energy.com/releases/duke-energy-will-seek-to-renew-nuclear-plant-licenses-to-support-its-carbon-reduction-goals
[85] DEP 2020 IRP, pg. 80.

operating and a second PROSYM run with the unit replaced with a peaker CT. The production cost difference between the two runs, the fixed costs of the peaker resource and the savings from early retirement of the studied coal unit were all used in the determination of the retirement cost savings. The analysis was performed for each year between 2025 and the planned retirement date of the studied unit as was modeled in the 2019 IRP.

Step 3 Portfolio Optimization – After the economic retirement dates were determined, the Company relied on the System Optimizer model to identify resources that it would need to satisfy its capacity requirements, including to fill the needs identified by retiring its coal units early as determined in Step 2.

The Company's retirement study concluded that it was economic to retire 3,440 MW of coal capacity through 2029.[86] The following table shows the retirements that the Company's economic coal retirement study determined.

Table 12
DEP Economic Coal Retirement Schedule
(2021 – 2035)

Unit	Type	Retire Year	Retire Month	Summer Capacity (MW)	Winter Capacity (MW)
Mayo 1	Coal	2028	12	727	746
Roxboro 1	Coal	2028	12	379	380
Roxboro 2	Coal	2028	12	665	673
Roxboro 3	Coal	2027	12	691	698
Roxboro 4	Coal	2027	12	698	711

Duke Energy's decision to retire the Allen units will affect both operating companies and appears to be reasonable in light of the current utilization of those units. The following table is based on historic data and demonstrates that the utilization of the Allen Plant has dropped significantly over the past ten years, to the point that it is no longer called on for intermediate duty, but it appears to be used strictly for peaking operation.

Table 13
Allen Plant Units 1 -5[87]

[86] DEP 2020 IRP pg. 102.

	Annual Generation (MWH)	Annual Capacity Factor (%)
2010	5,473,381	55%
2013	2,004,449	20%
2016	1,391,068	14%
2019	895,019	9%

In the 2019 IRP, the Company assumed that coal units would retire consistent with the retirement dates found in the Company's depreciation study that was used in its prior rate case.[88] Exhibit 1 below provides a list of important retirements and additions in the 2019 IRP, compared to the important dates in this IRP. The result is that the Allen units, which previously were all planned to retire between 2025 and 2029, are now moved up to retire between 2022 and 2024. In addition, the Mayo and Roxboro 1-4 units, which previously were all planned to retire between 2029 and 2036, are now moved up to retire between 2028 and 2029. Blewett and Weatherspoon have been moved back from a 2025 to 2026 retirements.

While the Company's modeling assumptions assume specific retirement dates, there are uncertainties as to when those retirements will actually occur. For instance, for modeling purposes, Allen Units 2 - 4 are assumed to retire in January 2022, which is less than a year away. Although the retirements of these Allen Units appear in the DEC's Short-Term Action Plan as depicted in Table 14-B of the IRP, DEC has repeatedly stated that:

> ….this is not a commitment to retire the Allen units on this timeline but rather contains the Company's most recent estimate of retirement economics at the time of this filing. Official retirement will require final management approval with final retirement dates contingent upon the finalization of the supporting switchyard project and other operational considerations.[89]

This is an important issue since there is less than a year until some of the Allen units are to be retired. ORS recommends Duke Energy provide additional clarity regarding its plans for the retirement of the Allen units, including details about the switchyard and any

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[87] EIA 923 Data at https://www.eia.gov/electricity/data/eia923/
[88] DEP 2019 IRP Report, pg. 91.
[89] DEC 2020 IRP pg. 83.

other required transmission upgrades, an explanation of the steps being pursued to receive final approval within the Company and from any regulatory body, and a timeline for conducting these activities.

ORS has one other concern that relates to the Company's retirement study. Step 2 was conducted using the SPM that relied on production cost runs. In one run, the studied coal unit was operated and in the other the studied unit was retired and a peaker unit was included as a replacement. Though the Company asserted that Step 2 determined the "optimal date for retirement", it is not clear this is necessarily true since the Company did not perform an optimization analysis to compare the retirement resources to optimal replacements. Instead, it simply assumed that the replacement to the studied unit would be a peaker unit. Only after the retirement date was determined and locked-in, did the Company run its optimization model to determine the optimal replacement resources. ORS recommends that the Company provide an explanation why it did not use its optimization model, System Optimizer, to conduct Step 2 of the retirement study, especially given that the System Optimizer is capable of conducting retirement analyses. In addition, ORS recommends that the Company be required to demonstrate that the SPM method did not derive different and less optimal retirement dates than what would have been derived had the Company's optimization model been used in Step 2.

<u>Recommendations - Existing System Resources</u>

10. To ensure there are no inconsistencies in modeling data, we recommend the Company create a cross reference table that compares each resource modeled in PROSYM, including generating units, demand response, purchase contracts, sales contracts, EE, etc. to the corresponding data in the LCR table, on a resource by resource basis. We recommend this be developed for both the Base Case with CO_2 and Base Case without CO_2 cases, and cover all of the years in the study period. We recommend this information be provided in a modified IRP in this proceeding. **(N)**

11. Recognizing that the Oconee units' licenses will not expire for about fifteen (15) years, that the Robinson 2 unit will expire in 2030, and that it only takes five (5) years to relicense units, we recommend the Company supply additional information regarding its relicensing plans (including a timeline) and its plans to conduct economic evaluations to assess the benefits of relicensing the units. We recommend the Company provide additional insight into why it is beginning this process so far in advance of the relicensing dates, and why Robinson 2 is

relicensing after Oconee. We recommend this information be provided in a modified IRP in this proceeding. **(N)**

12. Reserved
13. ORS recommends DEP provide additional clarification regarding its plans for the retirement of the Darlington units, including details about any transmission impacts. We recommend this information be provided in a modified IRP in this proceeding. **(N)**
14. ORS recommends the Company provide evidence that the optimal retirement dates that were determined with the SPM are comparable to the optimal retirement dates the System Optimizer model would produce if it were used in the retirement study. We recommend this information be provided in a modified IRP in this proceeding. **(N)**

Generic Resource Options

The Company reflected two categories of new resources in the six Portfolios that it modeled in its IRP. The first category of new resources were "forced-in," in other words, they were either added because they were already under contract, they were required pursuant to federal law and/or North Carolina statutory or regulatory requirements, or they were selected based on a desire to reduce carbon emissions.[90] Additional discussion of these forced-in resource types is found in the next section, Renewables.

The second category of new resources were selected from a list of generic resource options based on the economics of the resource, pursuant to a least cost criterion. The Company considered a wide range of technology options, including technologies that are not yet mature and/or available. The Company assembled assumptions associated with each of the generic resources, including capital costs, physical operating and other performance characteristics, emissions rates, fuel expenses, variable and fixed non-fuel O&M expenses, and other capital-related expenses, such as depreciation (based on estimated service or book lives), property taxes, and insurance. The Company relied on actual historic information, and/or forecast information based on trends in the Company's historic cost and performance data. It also relied on vendor cost and performance data, and used data from other sources, such as the Electric Power

[90] NCPS DR 3-14 defines "Base Solar" as "artificially added that represents both designated and mandated solar. Additionally, some undesignated solar, representing opportunities under SC Act 62 and assumptions regarding materialization of projects from the T&D queues, was also included in each portfolio." We presume this category is all forced, with mandated, designated, and undesignated represented within it.

Research Institute ("EPRI") Technical Assessment Guide, and Energy Information Administration ("EIA") information.

The Company considered more than sixty potential generic capacity resource types in its evaluation. To narrow the potential resource options down to a more manageable list, the Company first performed a Technical Screening Analysis that considered factors such as the status of development, environmental acceptability, fuel availability, commercial availability, and service territory feasibility. The Company provided explanations for eliminating certain resources based on its Technical Screening Analysis as follows:[91]

- Fuel cells – cost and performance issues limited use to niche markets and/or subsidized installations.
- Geothermal - no suitable sites in the region.
- Small Modular Reactors ("SMR") - lack of commercial availability. However, while SMRs were screened out, the Company did consider them in portfolios where high CO_2 emissions constraints were considered.
- Advanced Nuclear Reactors - expected availability not before the 2030 time period.
- Poultry waste and swine digesters – expensive, and operational and permitting challenges exist.
- Solar Steam Augmentation in a fossil generating plan – not economic compared to Solar PV.
- Supercritical CO_2 Brayton Cycle using CO_2 instead of H_2O – advanced technology which is not presently commercially available.
- Hydrogen – although promising, it is not presently commercially available.
- Compressed Air Energy Storage ("CAES") – proven, but overly expensive.
- Off-Shore Wind - high cost. Even though these were screened out, they were considered in some portfolios.

The Company further narrowed down the list of potential resource options based on an economic screening process. For this process, technology types were grouped within categories, including baseload, peaking/intermediate, renewable, and storage. DEP's IRP Table 8A identifies each of the resource types that were evaluated separately in these four categories.

[91] DEP 2020 IRP, pg. 310.

DEP's economic screening analysis was strictly a relative cost comparison of similar resource types and did not include production cost dispatch modeling. The analysis used a screening curve, or "busbar curve,"[92] approach that first required the capital revenue requirement on a PVRR basis for each technology type to be derived. Then the PVRR cost was levelized on a dollar per kilowatt-year ($/kW-year) basis over the operating life of the technology type. Finally, fuel costs, emissions costs, and non-fuel O&M expenses, were calculated at different assumed levels of capacity factor for the technology type and those costs were added to the PVRR cost. The final screening curve result was a cost function that varied over a range of capacity factors that the technology type could operate.

One resource whose screening curve is found to be higher than another over the entire range of capacity factors is considered to be more expensive than the other resource. The higher cost resource can then be "screened out" or eliminated from further modeling consideration. All remaining resources are passed on to the next stage of the analysis, which is a more detailed economic evaluation that relies on expansion plan optimization and production cost modeling. This screening process is an industry standard practice that is typically performed by utilities in IRPs. The following are the resources that DEP evaluated in its economic screening curve analyses.[93]

<u>Non-Renewable Resources</u>

- CTs, including 15 MW, 192 MW, 752 MW, and 913 MW sized alternatives of CT types.
- Reciprocating Engines, including 18 MW and 201 MW alternatives.
- CCGTs, with and without duct firing, including 601 MW and 1,224 MW alternatives.
- Coal with Carbon Capture and Sequestration ("CCS"), including a 782 MW alternative.
- Integrated Gasification Combined Cycle ("IGCC") with CCS, including 557 MW alterative.
- Nuclear, including 12 SMRs, 720 MW Total, and 2 AP1000s, 2,234 MWs Total.
- CHP, including 9 MW and 21 MW alternatives.

<u>Renewable Resources</u>

- Onshore and Offshore Wind, including 150 MW Onshore, and 600 MW Offshore alternatives.

[92] Response to NCPS 13-1, consisting of an Excel workbook.
[93] DEP 2020 IRP, pg. 320.

- Fixed and Single Axis Tracking ("SAT") Solar PV, including 75 MW alternatives of both types.
- Landfill Gas, including a 5 MW alternative.
- Wood-fired Bubbling Fluidized Bed ("BFB") Boiler, including a 75 MW alternative.

Storage Technologies

- PSH, including a 1,400 MW alternative.
- Lithium-Ion ("Li-Ion") Batteries, including:
  - 10 MW, 10, 20, and 40 MWh alternatives.
  - 50 MW, 200 and 300 MWh alternatives.
- Flow Batteries, including a 20 MW, 160 MWh alternative.
- Advanced CAES, including a 250 MW alternative.
- Hybrid Renewable and Storage, including a 75 MW SAT Solar PV with a 20 MW, 80 MWh Li-Ion Storage alternative.

The Company's baseload technology screening curve comparison is shown graphically on page 326 of its IRP, and the results suggest that natural gas fired resources and CHP resources are among the lowest cost all of the technology types considered.

ORS has one concern about CHP modeling. While it appears that CHP was found to be reasonably economic compared to the other alternatives, at least based on the Company's economic screening curve analysis, it is not clear if DEP modeled CHP resources as selectable resources in the economic optimization process. ORS recommends that DEP supply additional explanation of whether CHP resources were or were not treated as selectable resources in the economic optimization process.xThe Company's peaking technology screening results (page 327 of DEP's IRP) suggest that frame sized CTs without selective catalytic reduction technologies ("SCR") are the most economic resources compared to aeroderivative CTs and reciprocating engine generating units.

To evaluate the reasonableness of the Company's generic resource assumptions, ORS developed the following table that compares various assumptions for the Company's generic resources to assumptions for similar generic resources found in other publicly available sources. In addition to the Company's data, the table includes data from Virginia Electric and Power Company,[94] Kentucky Power Company,[95] Southwestern

[94] Appendix 5N – Busbar Assumptions; Appendix 5M – Tabular Results of Busbar; Virginia Electric and Power Company's 2020 Integrated Resource Plan. https://www.dominionenergy.com/-

Electric Power Company,[96] DESC 2020 IRP,[97] AEO report,[98] Lazard's 2019 Levelized Cost of Energy Analysis,[99] National Renewable Energy Lab ("NREL"),[100] the NRC[101]. The table includes information, to the extent it was applicable and/or available, for capacity, book life, capital cost, fixed and variable O&M expenses, average heat rate, capacity factor, and levelized cost of energy ("LCOE") for six generic resource types.

/media/pdfs/global/2020-va-integrated-resource-plan.pdf?la=en&rev=fca793dd8eae4ebea4ee42f5642c9509

[95] New Generation Technology Options with Key Assumptions, Exhibit D, p. 204, Kentucky Power 2019 Integrated Resource Planning Report; https://psc.ky.gov/pscecf/2019-00443/sebishop%40aep.com/12202019120748/KPCO_2019_IRP_Volume_A_Public_Version.pdf

[96] New Generation Technologies, Part III; Exhibit B, p.149; Description of Studies & Study Assumptions. https://lpscpubvalence.lpsc.louisiana.gov/portal/PSC/DocumentDetails?documentId=131242https://lpscpubvalence.lpsc.louisiana.gov/portal/PSC/DocumentDetails?documentId=131242

[97] DESC 2020 IRP Report, pg. 46. https://dms.psc.sc.gov/Attachments/Matter/0f53757a-4334-4fb8-81d4-00ca3b71d5e5

[98] Cost and Performance Characteristics of New Generating Technologies; U.S. Energy Information Administration's Annual Energy Outlook 2020. https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf

[99] Lazard's Levelized Cost of Energy Analysis – Version 14.0. https://www.lazard.com/media/451419/lazards-levelized-cost-of-energy-version-140.pdf

[100] NREL 2020 ATB, https://atb.nrel.gov/electricity/2020/data.php

[101] US NRC Replacement Energy Cost Estimates 2020, pg. 36. https://www.nrc.gov/docs/ML2034/ML20342A132.pdf

Table 14
Generic Resource Comparison

Combustion Turbine

	DEC & DEP	DESC	NREL (Low)	NREL (High)	Virginia Power	Kentucky Power	SWEPCO	Lazard (Low)	Lazard (High)	EIA AEO2020	NRC
Capacity (MW)	[redacted]	523				490	490	240	50	237	237
Book Life (yrs)	[redacted]		30	30	36			20	20		
Capital Cost ($/kW)	[redacted]	$ 469	$ 1,018.39	$ 1,018.39	$ 562	$ 673	$ 757	$ 675	$ 875	$ 661	$ 691
Fixed O&M ($/kW-yr)	[redacted]	$ 5.66	$ 11.80	$ 11.80		$ 24.99	$ 25.24	$ 7.25	$ 22.75	$ 7.10	$ 7.26
Variable O&M ($/MWh)	[redacted]	$ 0.34	$ 4.66	$ 4.66		$ 6.38	$ 6.38	$ 4.25	$ 5.75	$ 4.56	$ 11.42
Average Heat Rate (MBTU/MWh)	[redacted]	9,364	9,515	9,515	9,670	10,000	10,000	9,800	8,000	9,905	9,550
Capacity Factor (%)	[redacted]		30%	12%		25%	25%	10%	10%	30%	
LCOE	[redacted]		$ 57.57	$ 96.89		$ 119.31	$ 117.99	$ 151.00	$ 198.00	$ 69.95	

Combined Cycle

	DEC & DEP	Virginia Power	NREL (Low)	NREL (High)	Kentucky Power	SWEPCO	Lazard (Low)	Lazard (High)	EIA AEO2020	NRC
Capacity (MW)	[redacted]				1230	1230	550	550	1083	1100
Book Life (yrs)	[redacted]	36	30	30			20	20		
Capital Cost ($/kW)	[redacted]	$ 1,102	$ 1,127	$ 2,878	$ 673	$ 662	$ 650	$ 1,150	$ 885	$ 796
Fixed O&M ($/kW-yr)	[redacted]		$ 13.32	$ 27.96	$ 10.84	$ 10.84	$ 14 50	$ 18 50	$ 12.37	$ 10.67
Variable O&M ($/MWh)	[redacted]		$ 2.24	$ 5.93	$ 1.58	$ 1.58	$ 2.75	$ 5 00	$ 1.89	$ 2.13
Average Heat Rate (MBTU/MWh)	[redacted]	6,590	6,401	7,525	6,200	6,200	6,150	6,900	6,370	6,300
Capacity Factor (%)	[redacted]		87%	55%	75%	75%	70%	50%	87%	
LCOE	[redacted]		$ 30.34	$ 66.06	$ 57.11	$ 54.77	$ 44 00	$ 73 00	$ 37.27	

Battery Energy Storage

	DEC & DEP	DESC	NREL	Virginia Power	Kentucky Power	SWEPCO	EIA AEO2020	NRC
Capacity (MW)	[redacted]	100		30	10	10	50	30
Book Life (yrs)	[redacted]		15	10				
Capital Cost ($/kW)	[redacted]	$ 1,911	$ 1,692	$ 2,224	$ 1,828	$ 1,797	$ 1,454	$ 1,861
Fixed O&M ($/kW-yr)	[redacted]	$ -	$ 42.30		$ 39.69	$ 39.69	$ 25.14	$ 37.63
Variable O&M ($/MWh)	[redacted]	$ -	$ -		$ -	$ -	$ -	$ 7 52
Capacity Factor (%)	[redacted]		17%	15%	25%	25%		
LCOE	[redacted]				$ 159.93	$ 159.11		

Onshore Wind

	DEC & DEP	Virginia Power	NREL (Low)	NREL (High)	SWEPCO	Lazard (Low)	Lazard (High)	EIA AEO2020	NRC
Capacity (MW)	[redacted]				200	175	175	200	100
Book Life (yrs)	[redacted]	25	30	30		20	20		
Capital Cost ($/kW)	[redacted]	$ 1,926	$ 1,814	$ 2,963	$ 1,135	$ 1,050	$ 1,450	$ 1,530	$ 1,513
Fixed O&M ($/kW-yr)	[redacted]		$ 44.77	$ 44.77	$ 45.81	$ 27.00	$ 39.50	$ 26.69	$ 53.33
Variable O&M ($/MWh)	[redacted]		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capacity Factor (%)	[redacted]	40%	52%	16%	44%	55%	38%	40%	
LCOE	[redacted]		$ 29.34	$ 131.82	$ 15.88	$ 26.00	$ 54.00	$ 34.71	

Offshore Wind							
	DEC & DEP	Virginia Power	NREL (Low)	NREL (High)	Lazard (Low)	Lazard (High)	EIA AEO2020
Capacity (MW)	[redacted]				210	385	400
Book Life (yrs)	[redacted]	25	30	30	20	20	
Capital Cost ($/kW)	[redacted]	$ 2,952	$ 4,212	$ 7,100	$ 2,600	$ 3,675	$ 4,989
Fixed O&M ($/kW-yr)	[redacted]		$ 128.46	$ 103.60	$ 67.25	$ 81.75	$ 111.51
Variable O&M ($/MWh)	[redacted]		$ -	$ -	$ -	$ -	$ -
Capacity Factor (%)	[redacted]	42%	44%	30%	52%	48%	45%
LCOE	[redacted]		$ 100.39	$ 206.35	$ 69.00	$ 104.00	$ 117.11

Utility Solar										
	DEC & DEP	DESC	Virginia Power	SWEPCO	Lazard (Low)	Lazard (High)	EIA AEO2020	NREL (Low)	NREL (High)	NRC
Capacity (MW)	[redacted]	100		50	150	150	150			150
Book Life (yrs)	[redacted]		35		30	30		30	30	
Capital Cost ($/kW)	[redacted]	$ 1,151	$ 1,363	$ 1,419	$ 975	$ 825	$ 1,327	$ 1,658	$ 1,658	$ 973
Fixed O&M ($/kW-yr)	[redacted]	$ -		$ 15.27	$ 13 50	$ 9.50	$ 15.46	$ 19.44	$ 19.44	$ 8.12
Variable O&M ($/MWh)	[redacted]	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capacity Factor (%)	[redacted]		25%	28%	34%	21%	30%	35%	22%	
LCOE	[redacted]	$ 47.77	$ 58 36	$ 51.71	$ 31 00	$ 42.00	$ 30.94	$ 30.21	$ 48.70	

Conclusions – Generic Resources

The Company's assumptions generally appear to be reasonable for many of the generic resource type assumptions, when compared to the other sources of data. There are, however, some items that warrant additional consideration.

In the CT comparison, DEP's capital cost assumption appears to be low compared to the other data, except for Dominion Energy (both Virginia Power and South Carolina). It should be noted, that in the DESC's 2020 IRP, DESC was criticized for the fact that its CT capital cost assumption appeared to be too low. DESC explained that it based its assumption on a volume discount that was available to its company; however the availability of such discounts over the long-term was disputed, and in the ordering paragraphs of the DESC 2020 IRP Order, the Commission ordered DESC to "use industry accepted ICT capital cost assumptions, such as NREL."[102] ORS recommends that DEP provide additional justification for its CT capital cost assumption.

In the Battery Energy Storage comparison, DEP's capital cost assumption appears to be at the high end of the range of estimates, though its cost is not the highest compared to all of the other sources. However, DEP's fixed O&M estimate appears to be out of

[102] December 23, 2020, Commission Order No. 2020-832, DESC 2020 IRP, Docket No. 2019-226-E, pg. 90, Ordering Paragraph v.

line with the other estimates and ORS recommends that DEP provide additional justification for its fixed O&M cost assumption. Also, DEP's capacity factor assumption appears to be too low compared to the other available sources, and ORS recommends that DEP provide additional justification for its capacity factor assumption, which may also explain why DEP's LCOE value is so high compared to the other sources.

It is ORS's position that the Company's utility scale solar capital cost and fixed O&M cost assumptions warrant additional consideration. Though DEP's capital cost assumption could hardly be considered out of line when compared to the other utility forecasts, its ultimate LCOE cost appears to be high relative to the other estimates. This leads to a question as to whether the utility's assumed revenue requirement for a solar resource is the only solar resource option assumption that should be evaluated in an IRP. In its recent DESC 2020 IRP Order, the Commission found that:[103]

> The parties provided ample testimony that solicitation of solar and/or storage resources via a competitive solicitation has the potential to create opportunities for ratepayer savings, by allowing the utility to procure energy from such resources more cheaply than it can generate it.

Part of the evidence that the Commission cited to in reaching this conclusion was the South Carolina Solar Business Alliance's testimony that DEP's own solicitation in North and South Carolina resulted in the procurement of solar resources at an average price of $38/MWh,[104] which is far lower than the LCOE of $[redacted]/MWh that appears in the table above for DEP's generic solar resource. ORS recommends the Company include an additional solar generic resource option in its IRP modeling that reflects the kind of solar PPA prices that may be available in the market.

ORS has one final Generic Resource conclusion, which relates to the Company's capacity value assumptions for standalone solar and solar plus battery storage resources. As discussed in the Resource Adequacy – Reserve Margin Issues section above, Astrapé derived capacity value assumptions based on a SERVM model analysis. These capacity values represent the percentage of installed nameplate capacity that contributes to meeting peak loads in the summer and winter, and since the winter peak drives the need for capacity, the winter capacity values of solar and solar plus battery are of the main importance.

The Company used a 1% winter capacity value for standalone solar and a winter capacity value of 25% for solar plus battery energy storage, based on an assumed 4-

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[103] *Id*. pg. 85.
[104] *Id*. pg. 47.

hour discharge assumption. Given the importance that this assumption has on the IRP analysis, ORS recommends that further investigation be conducted regarding these values. One investigation that could be performed would be to assess the impact on the Company's base case resource plan if higher winter capacity value ratings were assumed such as 5% for solar and 30% for solar plus battery energy storage. This investigation should be discussed in a future IRP as part of the Company's stakeholder engagement process.

Recommendations - Generic Resource Options

15. ORS recommends the Company explain whether CHP resources were or were not treated as selectable resources in the economic optimization process, if in fact they were not. We recommend this information be provided in a modified IRP in this proceeding. **(N)**

16. ORS recommends DEP provide additional justification for its CT capital cost assumption. We recommend this information be provided in a modified IRP in this proceeding. **(N)**

17. ORS recommends DEP provide additional justification for its Battery Energy Storage fixed O&M cost and capacity factor assumptions. We recommend this information be provided in a modified IRP in this proceeding. **(N)**

18. ORS recommends the Company include an additional solar generic resource option in its IRP modeling assumptions that reflects the kind of solar PPA prices that may be available in the market. As a proxy, the Company could assume $38/MWh as the solar PPA cost. We recommend this be addressed in a modified IRP in this proceeding. **(N)**

19. Given the importance that solar capacity values and solar plus battery energy storage capacity values potentially could have on the IRP analysis, ORS recommends that further investigation be conducted regarding these values with stakeholder input, discussed as part of a stakeholder engagement process. One investigation that could be performed would be to assess the impact on the Company's base case resource plan if higher winter capacity value ratings were assumed such as 5% for solar and 30% for solar plus battery energy storage. We recommend this be addressed in the future through the Company's stakeholder process. **(L)**

Renewables

DEP's detailed economic evaluations of its six (6) Portfolios considered several types of renewable resources including Solar, Battery Energy Storage, Solar plus Battery Energy Storage, Offshore Wind, Central-US Wind, and PSH. Both solar and battery energy storage made up a sizable percentage of renewable resources that were added in each of the portfolios. The Company's IRP resulted in new resources being added by either being "forced-in" or selected based on its optimization process. The Company further grouped resources that were forced-in into three categories that it refers to as "Designated", "Mandated" and "Undesignated" resources.

Designated, Mandated, and Undesignated Resource Categories

Mostly, these categories apply to renewable resources, but they also apply to other types of resources as well. The definitions of these categories are:

- **Designated Resources -** owned resources that DEP has already committed to add or third party owned resources that are already connected or will be connected but have a signed PPA.
- **Mandated Resources -** resources that are not yet under contract but are required under statutory or regulatory requirements.
- **Undesignated** – resources that are neither designated nor mandated. This includes solar resources that will be added upon expiration of designated solar contracts as replacement resources.

Examples of designated and mandated resources include various renewable resources, as well as nuclear uprates.

Many of the mandated, designated and undesignated resources that will be added to the system are solar resources, and Figure 5-A on pg. 44 of the Company's IRP Report contains a graph showing mandated, designated, and undesignated solar resources.

Mandated solar stems from a combination of federal and state statutory and regulatory requirements. The different categories of requirements are detailed in ORS AIR 2-6 and Table 15 below, but we point out that certain North Carolina statutes require more renewable resources to be added than would otherwise be required in South Carolina. For example, NC House Bill 589 requires both DEC and DEP to procure capacity in the aggregate amount of 2,660 MW ("initial Targeted Amount") from renewable resources through a competitive procurement program known as the North Carolina CPRE, which requires capacity be acquired over a term of 45 months in tranches starting from February 2018.

As far as acquiring the remainder of the CPRE capacity, the Company states that acquisition of the remaining capacity will depend on the final results of Tranche 2, as well as the continued increases in capacity that the Company referred to in its IRP Report as “Transition MW”. DEP defined transition MWs as the total capacity of renewable generation projects in the combined Duke Balancing Authority area that are 1) already connected, or 2) have entered into PPAs and interconnection agreements (IAs) as of the end of the 45-month competitive procurement period, and which are not subject to curtailment or economic dispatch. The CPRE capacity will be reduced by the amount of excess Transition MWs that DEP and DEP combined will have.

Table 15[105]
Base Case With CO_2

DEP Solar Capacity	NC Greensource	NC H.B.589	PURPA/ Act 62	CPRE	Act 236	SC Greensource Advantage	Utility Owned	Future Growth	Total DEP Capacity
2021	0	0	2,728	7	16	0	137	0	2,888
2022	0	3	2,876	85	16	0	164	0	3,144
2023	0	5	3,157	85	16	4	164	0	3,430
2024	0	47	3,250	164	16	15	163	0	3,655
2025	0	129	3,368	164	16	26	162	0	3,864
2026	0	211	3,554	163	15	37	161	0	4,141
2027	0	211	3,586	162	15	37	160	100	4,272
2028	0	212	3,618	161	15	36	160	200	4,402
2029	0	212	3,650	160	15	36	159	299	4,531
2030	0	211	3,632	160	15	36	158	547	4,759
2031	0	211	3,614	159	15	36	157	794	4,986
2032	0	210	3,596	158	15	36	156	1,015	5,187
2033	0	210	3,578	157	15	36	156	1,235	5,387
2034	0	211	3,560	156	15	35	155	1,454	5,586
2035	0	211	3,542	156	15	35	154	1,672	5,785

Table 15 above, includes Future Growth solar resources, which appear to be the economically selected resources in DEP’s IRP. The table shows that by 2035, economically selected resources will account for approximately 29% (1,672/5,785) of the total solar resources that will be added to DEP’s system by 2035, and the rest,

[105] ORS AIR 2-6d. Note that the actual CPRE forecast of 1,860 MW cannot be discerned from ORS AIR 2-6d. DEP would have to supply additional information to identify the CPRE MWs.

which appear to be forced-in resources will amount to approximately 71% (4,113/5,785) of the solar resources that will be added to DEP's system. It is not clear how much of this forced-in solar capacity would have been selected by an optimization model in the absence of these mandates.

ORS has presented one estimate of the amount of the solar resources that will be added to DEP's system over the planning horizon; however, the Company also supplied other data in other discovery responses that we found to be inconsistent. For instance, the amount of "mandated" annual solar resource additions shown in DEP's IRP Report in Figure 5-A do not seem to be consistent with the amounts that can be discerned from ORS AIR 2-6. For this section, ORS ultimately relied on the data that was provided in ORS AIR 2-6, because it provided the level of detail that ORS needed for its evaluation. The Company's response to NCPS DR 7-1 provides another example of renewable resource capacity addition results that do not appear to match with the data that was supplied in ORS AIR 2-6. The interrelationships between forced/economic resource additions, and between designated/mandated/undesignated renewable resources are unclear. ORS recommends that the Company provide a table identifying each renewable resource option that was modeled, whether the resource was forced-in or economically selected and the process by which it was economically selected (System Optimizer or other approach), the reason the resource was forced-in (e.g. CPRE, Act 236, etc.), whether the resource is a designated, mandated, or undesignated resource, and where the resource is found in the PROSYM database and in the LCR tables for reconciliation purposes. Ultimately, data supplied in tables, figures and discovery responses should be consistent.

<u>Recommendations - Renewables</u>

20. ORS recommends the Company provide a table identifying each renewable resource option that was modeled, and include whether the resource was forced-in or economically selected (System Optimizer or other approach), the reason the resource was forced-in (e.g. CPRE, Act 236, etc.), whether the resource is a designated, mandated, or undesignated resource, and where the resource is found in the PROSYM database and in the LCR tables for reconciliation purposes. We recommend this information be provided in a modified IRP in this proceeding. **(N)**

Resource Planning

Summary of Base and Other Portfolios

The Company's 2020 IRP includes six portfolios, or potential "pathways," that attempt to reflect and assess how the Company's resource portfolio may evolve over the 15-year study period (2021 through 2035) based on current data and assumptions across a spectrum of potential futures.[106] The following summarizes the portfolios that were considered:

Portfolio A - Base Case Without CO_2 - Economic coal retirement dates, no CO_2 policy.

Portfolio B - Base Case With CO_2 - Economic coal retirement dates, with CO_2 policy.

Portfolio C - Earliest practicable coal retirement dates.

Portfolio D - 70% CO_2 Reduction High Wind – Earliest practicable coal retirement dates, relying on more wind resources (on-shore and off-shore).

Portfolio E - 70% CO_2 Reduction High SMR – Earliest practicable coal retirement dates, relying on small modular reactors.

Portfolio F - No New Gas – Economic coal retirement dates, replaces economic additions of natural gas units with battery storage and renewable resources.

The Company recognizes that it is obligated to develop an IRP based on the policies in effect at this time, and accordingly, Portfolio A reflects existing environmental policies and represents the most economic scenario of the six Portfolios on a present value revenue requirement and non-risk adjusted basis. To assess the impact that potential new federal and state policies may have on future resource additions and in response to stakeholder feedback, the Company's 2020 IRP includes five other portfolios (B through F) that were developed to achieve sequentially greater levels of carbon emission reductions.

Portfolios B through F go beyond the regulatory policies and statutory requirements in effect at this time and provide insight into the effects of potential changes in those policies and statutory requirements over the study period. Factors that will influence the adoption of Portfolios B through F include the pace of carbon reduction goals, technology availability and commercial maturation, reliability and other operational considerations, and cost to customers. These portfolios address the most economic and earliest practicable paths for coal retirement; acceleration of renewable

[106] A summary of the resource additions reflected in each of the six portfolios were provided by DEC and DEP in response to NCPS DR7-1.

technologies including solar, battery and PSH, onshore and offshore wind; integration of renewable resources; expanded implementation of energy efficiency and demand response; and deployment of new zero-emitting load following resources (ZELFRs), such as SMRs.

Portfolios A, B, and F rely on the economic coal retirement date assumptions, which include retirements of DEP's coal-fired resources in 2026, 2028, and 2029, resulting in cumulative retirements of 3,954 MW (winter ratings),[107] over the 15-year study period. Portfolios C through E rely on accelerated coal retirement dates, which are accelerated to the earliest practicable dates in order to address more aggressive potential carbon reduction targets. All coal units are assumed to retire prior to 2030.

The following table presents the incremental resources that were selected in DEP's planning process for each of the six (6) portfolios over the 2021 – 2035 time period. The table separates the incremental resource additions by those that DEP forced-in to its database without having selected them through an economic optimization process (also referred to as Base resources), and by resources that DEP selected economically based on its optimization process.

Table 16
Comparison of Incremental Resources Added (MW)
Categorized by Forced-In Resources and Economically Selected Resources
By Portfolio (2021 - 2035)

Forced-In Resources	**A**	**B**	**C**	**D**	**E**	**F**
Solar	1,662	1,662	1,662	1,337	1,337	1,337
Solar + Storage	339	339	339	2,599	2,599	2,599
Grid-Tied 4hr Batteries	117	117	1,120	1,120	1,120	2,170
Grid-Tied 6hr Batteries						1,914
Grid-Tied 8hr Batteries						
Offshore Wind				1,384	92	2,492
Oklahoma Wind				529	422	422
Nuclear SMR					684	
Total Forced-In Resources	2,117	2,117	3,120	6,968	6,253	10,933

[107] Tables 12-F and 12-G of DEP and DEP IRP Reports.

Economically Selected Resources	**A**	**B**	**C**	**D**	**E**	**F**
Solar						
Solar + Storage		1,425	1,500	900	900	1,050
On-Shore Wind		600	1,350	1,200	1,200	1,200
CC	1,224	2,448	1,224	1,224	1,224	
CT	4,113	1,828	2,742	914	914	
Grid-Tied 4hr Batteries	481	1,136				
Total Economically Selected Resources	5,818	7,437	6,816	4,238	4,238	2,250
Total Incremental Resources Added	7,935	9,554	9,936	11,206	10,491	13,183

The following table is similar to the table above, but it sums together the forced-in and economically selected resources by category.

Table 17
Comparison of Incremental Resources Added (MW)
By Portfolio (2021 - 2035)

Total Incremental Resources Added	**A**	**B**	**C**	**D**	**E**	**F**
Solar	1,662	1,662	1,662	1,337	1,337	1,337
Solar + Storage	339	1,764	1,839	3,499	3,499	3,649
Battery Energy Storage	117	117	1,120	1,120	1,120	4,084
Wind		600	1,350	3,113	1,714	4,114
Nuclear SMR					684	
CC	1,224	2,448	1,224	1,224	1,224	
CT	4,113	1,828	2,742	914	914	
Grid-Tied 4hr Batteries	481	1,136				
Total Incremental Resources Added	7,935	9,554	9,936	11,206	10,491	13,183

The following provides additional descriptions of the six (6) Portfolios.

Portfolio A (Base Case without Carbon)

The Company's Portfolio A is the Base Case without CO_2 plan. In addition to the retirements of existing coal-fired resources, it features additions of new "base" solar resources, starting in 2021 and each year thereafter which result in cumulative additions of 1,662 MW through 2035. Additionally, there are "base" solar + storage resources, which result in cumulative additions of 339 MW through 2035. Also included are additions of Battery Energy Storage resources of 598 MW through 2035. Portfolio A includes additions of new gas-fired combustion turbine resources in 2028, 2029, 2032, 2034, and 2035, resulting in cumulative additions of 4,113 MW, and additions of 1,224 MW of new gas-fired combined-cycle resources through 2035.

Portfolio B (Base Case with Carbon)

Portfolio B is the same as Portfolio A, which uses the economic coal retirement schedule, but it incorporates a carbon tax starting at $5 per ton in 2025, escalating at $5 per ton annually thereafter, which makes additional renewables resources economical, and delays and displaces new gas-fired resources. It includes:

1. same base solar, solar + storage and grid-tied 4-hour batteries as in Portfolio A.
2. 1,425 MW of new solar + storage additions starting in 2019 and each year thereafter through 2035.
3. additions of new onshore wind in 2032 and each year thereafter, resulting in cumulative additions of 600 MW through 2035.
4. delays in additions of new natural gas-fired CT resources to 2025, 2026, and 2028, resulting in cumulative additions of 1,828 MW through 2035.
5. delays in additions of new natural gas-fired CCGT resources 2027 and 2028, resulting in cumulative additions of 2,448 MW through 2035.
6. incremental additions of new grid-tied batteries in 2021 and each year thereafter through 2026 and 2030 and 2034, resulting in cumulative incremental additions of and 1,136 MW through 2035.

Portfolio C (Earliest Practicable Coal Retirements)

Portfolio C is the same as Portfolio B, except that it reflects accelerated retirements of existing coal-fired resources, accelerated and incremental additions of new renewables resources, and accelerated and incremental additions of new gas-fired combustion turbines and combined cycle resources. It includes:

1. same base solar and solar + storage as in Portfolio A.
2. incremental additions of new solar + storage resources starting in 2028 and each year thereafter through 2035, resulting in cumulative incremental additions of 1,500 MW.
3. incremental additions of new onshore wind resources in 2026, 2028, and each year thereafter, resulting in incremental additions of 1,350 MW.
4. acceleration in additions of new natural gas-fired CT resources to 2025, 2027, 2028, and 2034, resulting in cumulative additions of 2,742 MW.
5. additions of new natural gas-fired CCGT resources in 2027, resulting in cumulative additions of 1,224 MW through 2035.
6. incremental additions of new grid-tied batteries in 2021 and each year thereafter through 2026, resulting in cumulative incremental additions of 1,120 MW.

Portfolio D (70% Carbon Reduction; High Wind)

The Company's Portfolio D is the plan with a 70% carbon reduction and high incremental additions of new wind resources. The Company forces-in a greater amount of solar using its assumed "high solar" sensitivity parameters. Portfolio D is reflects accelerated and incremental additions of new renewables resources to meet the 70% carbon reduction target. It includes:

1. "high" solar additions of 1,337 MW, high solar + storage additions of 2,599 MW, and grid-tier 4-hour batteries additions of 1,120 MW.
2. incremental additions of new solar + storage resources starting in 2029 and each year thereafter through 2035, resulting in cumulative incremental additions of 900 MW.
3. delay in incremental additions of new onshore wind resources starting in 2028 and each year thereafter through 2035, resulting in incremental additions of 1,200 MW.
4. incremental additions of new Oklahoma wind resources in 2028 and each year thereafter, resulting in incremental additions of 529 MW.
5. incremental additions of new offshore wind resources in 2034 and 2035, resulting in incremental additions of 1,384 MW.
6. additions of new natural gas-fired CT resources in 2027, resulting in cumulative additions of 914 MW.
7. additions of new natural gas-fired CCGT resources in 2027, resulting in cumulative additions of 1,224 MW.

Portfolio E (70% Carbon Reduction; High SMR)

The Company's Portfolio E is the plan with a 70% carbon reduction, and it includes 684 MW of SMR Nuclear reactors in place of some of the wind energy in Portfolio D. It includes:

1. same high solar, high solar + storage, and grid-tied 4-hour batteries as in Portfolio D.
2. incremental additions of new solar + storage resources starting in 2029 and each year thereafter through 2035, resulting in cumulative incremental additions of 900 MW.
3. incremental additions of new onshore wind resources starting in 2028 and each year thereafter through 2035, resulting in incremental additions of 1,200 MW.
4. incremental additions of new offshore wind resources in 2035, resulting in incremental additions of 92 MW.
5. incremental additions of new Oklahoma wind resources in 2030 and each year thereafter through 2035, resulting in incremental additions of 422 MW.
6. incremental additions of new natural gas-fired CT resources in 2027, resulting in cumulative additions 914 MW.
7. incremental additions of new SMRs in 2029, resulting in cumulative additions of 684 MW.

8. additions of new natural gas-fired CCGT resources in 2027, resulting in cumulative additions of 1,224 MW.

Portfolio F (No New Gas Generation)

The Company's Portfolio F is the plan that reflects no new gas-fired resources. The Company forces-in a greater amount of solar using its assumed "high solar" sensitivity parameters targets. There is a large amount of new grid-tied battery resources to provide capacity in place of the natural gas plants that would have otherwise been built. It includes:

1. same high solar and high solar + storage as in Portfolio D.
2. incremental additions of new solar + storage resources starting in 2029 and each year thereafter through 2035, resulting in cumulative incremental additions of 1,050 MW.
3. incremental additions of new onshore wind resources starting in 2028 and each year thereafter through 2035, resulting in incremental additions of 1,200 MW.
4. incremental additions of new Oklahoma wind resources in 2030 and each year thereafter through 2035, resulting in incremental additions of and 422 MW.
5. incremental additions of new offshore wind resources in 2028-2030, and 2035, resulting in incremental additions of 2,492 MW.
6. no incremental additions of new natural gas-fired CT or CCGT resources.
7. incremental additions of new grid-tied 4 hour batteries in 2021 and each year thereafter through 2027, resulting in cumulative incremental additions of 2,170 MW.
8. incremental additions of new grid-tied 6 hour batteries in 2027, 2029, and 2034, resulting in cumulative incremental additions of 1,914 MW.

Conclusions – Resource Planning

The Company's six portfolios demonstrate that the Company has identified a broad range of demand-side, supply-side, storage and other technologies, as required by Act 62. The portfolios allow for consideration of different coal retirement schedules, renewables, advanced technologies, and aggressive CO_2 targets. In addition, the Company conducted a reasonable set of sensitivity analyses. The only concern, which is discussed in the Generic Resources section of this report, relates to the cost that was assumed for solar resources. The Company's assumed capital cost for solar resources is higher than was found in other sources that were considered and this may have affected the amount of solar selected economically had the cost been lower and more consistent with the other sources.

Economic Evaluation of Portfolios and Sensitivities

As discussed above in the Generic Capacity Resources section, the Company conducted a technology and economic screening process in order to develop a manageable set of potential generation alternatives. The Company screened generating technologies from both a technical perspective and an economic perspective. Once options are screened out, the remaining resources are passed on to the more detailed economic evaluation that relies on expansion plan optimization and production cost modeling.

In the detailed economic evaluation, the Company first assessed the remaining resources that it would need to satisfy its 17% winter target reserve margin criteria. When the Company constructed its production cost database, it included existing system resources and it fixed into the database all of the mandated, designated, and undesignated resources that it is or will be obligated to acquire either by statute, regulation, or for other reasons. This includes resources that were already considered committed. In addition, the Company included the coal retirement dates for each portfolio being studied.

The results of the System Optimizer model provided a list of economic generating resource additions that satisfied the Company's reserve margin criteria for each of the six (6) portfolios it evaluated. Based on the list of all incremental capacity additions to its system, the Company conducted both production cost modeling analysis to develop more detailed production cost and capital revenue requirement results for each portfolio. The end result of the analysis was that the Company developed nominal dollar annual total revenue requirements and the net present value of these revenue requirements for the fifteen-year study period (2021 through 2035) and a thirty-year study period (2021 through 2050) for each Portfolio and each sensitivity of each Portfolio, a total of 54 cases.

The Company developed the annual total revenue requirements in separate Excel workbooks for each of the 54 cases.[108] Annual total revenue requirements were derived for each Portfolio and each sensitivity case, including the following components:

- production expense (fuel and variable O&M expenses),
- fixed fuel (demand) expense,

[108] Response to ORS 2-10c, consisting of 54 confidential "PVRR" Excel workbooks with separate sheets summarizing the annual total revenue requirements and each of the costs rolling forward into the summary and the net present value of the revenue requirements for the 15-year and 30-year study periods.

- carbon tax expense (for Portfolios B through F only) for the Company's entire system of existing and new resources,
- fixed O&M expenses,
- generation capital revenue requirements,
- transmission capital revenue requirements including infrastructure and interconnection costs for new resource additions.

In addition, the annual total revenue requirements include the capital and fixed operation and maintenance expense for existing coal-fired resources based on the retirement dates for the specific case modeled (either economic retirement dates or most practical retirement dates). However, the annual total revenue requirements do not include post-in-service capital expenditures and the related expenses, except for the battery resources, which include these costs in fixed O&M expenses.

The Company utilized the PROSYM production cost model to quantify the production cost expenses (variable and fixed) and CO_2 costs for the Company's system, including existing and new resources for each Portfolio and each sensitivity case. The production cost results were then loaded into the Excel PVRR workbooks.

The Company utilized an Excel workbook "capital cost" revenue requirement model and a "fixed charge rate" model to calculate unique fixed charge rates for the capital costs and capital-related expenses for each new generic resource. The "capital cost" model relied on the "fixed charge rate" model for each new generic resource included in each Portfolio.[109] The "capital cost" model calculated the annual nominal levelized capital revenue requirement cost for each generic resource. The "capital cost" model then utilized and escalated the annual nominal levelized capital costs for each new generic resource addition included in each Portfolio.[110] It also calculated the present value of the nominal dollar annual capital costs in 2020 dollars for the period 2020 through 2050.

The "fixed charge rate" model calculated a unique real levelized fixed charge rate for each new generic resource using common information, such as the cost of capital, and resource specific information, including capital (construction) cost, capital spend curve, AFUDC, inflation (escalation), book life, tax depreciation method and life, investment tax credit availability, and federal and state income rates, among others.

The Company summarized the PVRR for each Portfolio in its IRP Report in 2020 dollars from 2021 through 2050 assuming the base fuel forecast and no carbon tax, on a non-

[109] Response to ORS 2-10d, consisting of two confidential Excel workbooks, one for the "capital cost" model and the other for the "fixed charge rate" model.
[110] Response to ORS 5-5.

risk adjusted basis.[111] The least cost Portfolio, on a non-risk adjusted basis, is Portfolio A, with a PVRR of $35.4 billion, which includes transmission costs of $0.4 billion.

The highest cost Portfolio, on a non-risk adjusted basis, is Portfolio F, with a PVRR of $52.1 billion, which includes transmission costs of $6.2 billion.

Portfolio B has a PVRR of $35.7 billion, although the PVRRs for Portfolios B through F do not include the PVRR of the carbon tax itself. The Company estimates that the PVRR of the carbon tax itself ranges from $5 billion to $8 billion.

The Company also summarized the PVRR for each Portfolio fuel and carbon tax sensitivity (nine for each Portfolio) in its IRP Report, which provides a quantitative assessment of the range of PVRR results for each Portfolio by varying these key assumptions.[112]

Conclusions - Economic Evaluation of Portfolios and Sensitivities

The Company's analysis is detailed and provides reasonable quantifications of the costs for each Portfolio and each sensitivity for planning purposes based on the Portfolios and sensitivities that were studied and given the assumptions utilized to model the existing resources, especially fuel, variable operation and maintenance expenses, and purchased power expenses and operating performance existing and new resources in PROSYM; capital costs of existing coal-fired resources subject to retirement; transmission capital costs necessary if existing coal-fired resources are retired; and capital costs, fixed operating expenses, transmission infrastructure costs, and other assumptions necessary to model new generic resource additions. To the extent these assumptions are modified, then the quantifications will change and the relative differences between and among the Portfolios and the sensitivities will change.

The Company's calculation of PVRR is detailed, but includes a mixture of annual production expenses as incurred or forecast to be incurred and capital revenue requirements that have been levelized over the resources' estimated service lives, not the annual revenue requirements as they will be incurred through the regulatory process. This is appropriate for economic evaluations of potential portfolios for planning purposes, but would not be appropriate for rate impact analyses, as it would understate the near-term rate impacts of the Company's plans to transform its generation resources through retirements of existing coal-fired resources, and the longer-term rate impacts of replacement of those resources with new renewables and gas-fired

[111] DEP 2020 IRP, Portfolio Results Table, pg. 17.
[112] DEP IRP Report Table 12-C, pg. 99.

generation during the 15-year study period. For this reason, the Company performs separate calculations of the annual rate impacts of its portfolios, which properly address this issue and allow the Commission to balance the economic evaluation against the rate impact of the portfolios.

The Company's calculation of PVRR does not reflect the post-in-service capital expenditures and the related expenses, except for the battery resources, which include these costs in fixed O&M expenses. At page 171 of the DEP IRP Report, the Company states that in some cases, battery storage resources were determined to be less economic than CT assets. The Company did include capital addition costs for battery storage resources in the form of battery cell replenishment (augmentation) costs. Leaving out CT capital addition costs would understate the CT costs and should be investigated further.

Recommendations - Economic Evaluation of Portfolios and Sensitivities

21. ORS recommends the Company include post in-service capital costs for new resource additions in its capital cost model and its PVRR calculations for each Portfolio and each sensitivity of each Portfolio. We recommend this be addressed in a modified IRP in this proceeding. **(N)**

Risk Analysis

Each of the Portfolios and sensitivities reflect a range of risks due to an unknown and uncertain future over the study period. The Company analyzed nine sensitivities for each of the six Portfolios, for a total of 54 cases.

In Appendix A the Company compared each Portfolio on a PVRR basis across three carbon price scenarios (zero, base, and high cases), and three natural gas forecasts (low, base, and high cases), for a total of nine sensitivities.[113]

To assess the relative risk, ORS performed a Minimax Regret Analysis and an analysis of the variability within each portfolio using each Company's PVRR results.[114] The results are shown in Table 18. The values in the DEP Portfolio Regret Tables below represent the PVRR amount by which each Portfolio exceeds the lowest cost Portfolio in each fuel cost and CO_2 price case.

[113] DEP 2020 IRP, Appendix A, pg. 188.

[114] A regret analysis quantifies the amount by which a given portfolio exceeds the least-cost portfolio. It is a means to understand the risks associated with each portfolio given the uncertainty in future fuel and carbon prices. A portfolio with a small amount of regret across a variety of pricing scenarios is robust to a variety of futures.

TABLE 18

Minimax Regret Analysis	Base Plan without Carbon Policy	Base Plan with Carbon Policy	Earliest Practicable Coal Retirements	70% CO_2 Reduction: High Wind	70% CO_2 Reduction: High SMR	No New Gas Generation
High CO_2-High Fuel	\$0.90	\$0.00	\$1.00	\$4.50	\$2.20	\$11.60
High CO_2-Base Fuel	\$0.20	\$0.00	\$1.00	\$5.40	\$3.10	\$13.10
High CO_2-Low Fuel	\$0.00	\$0.20	\$1.30	\$6.20	\$3.90	\$14.00
Base CO_2-High Fuel	\$0.40	\$0.00	\$1.00	\$5.10	\$2.90	\$12.50
Base CO_2-Base Fuel	\$0.00	\$0.40	\$1.40	\$6.40	\$4.20	\$14.30
Base CO_2-Low Fuel	\$0.00	\$0.70	\$1.80	\$7.30	\$5.10	\$15.40
No CO_2-High Fuel	\$0.00	\$1.10	\$2.20	\$8.00	\$5.80	\$16.10
No CO_2-Base Fuel	\$0.00	\$1.90	\$3.00	\$9.60	\$7.50	\$18.20
NO CO_2-Low Fuel	\$0.00	\$2.30	\$3.40	\$10.60	\$8.50	\$19.30

The values in Table 19 below compare the variability within each portfolio, e.g., the amount each portfolio's PVRR changes from scenario to scenario. From a pure variability perspective, the highly renewable options are the best performing. Although the high renewable cases are not as susceptible to variability in natural gas prices and perform well under carbon constrained cases, their higher capital costs outweigh the potential savings. In the end, the low variability cases result in higher prices being locked in.

The Base Portfolio without Carbon Pricing has the lowest maximum regret result. It also has the lowest Regret variability.

TABLE 19

Minimax Regret Analysis	Base Planning without Carbon Policy	Base Planning with Carbon Policy	Earliest Practicable Coal Retirements	70% CO_2 Reduction: High Wind	70% CO_2 Reduction: High SMR	No New Gas Generation
Max Regret	\$0.90	\$2.30	\$3.40	\$10.60	\$8.50	\$19.30
Mean Regret	\$0.17	\$0.73	\$1.79	\$7.01	\$4.80	\$14.94
Regret Standard Deviation	\$0.31	\$0.86	\$0.90	\$2.07	\$2.14	\$2.57

These results suggest that if higher natural gas and CO_2 prices were modeled in the different scenarios, the outcome would be that the renewable heavy portfolios perform comparatively better.

Customer Rate Impacts

In addition to the calculations of PVRR for planning purposes, the Company calculated the average retail and residential rate (bill) impacts on an annual nominal dollar basis and presented the cumulative rate impacts in 2030 and 2035 in its IRP Report.[115] It calculated the annual revenue requirement for each Portfolio using the incremental investment and incremental expenses for each portfolio and then added the incremental revenue requirement to the present average retail and residential rates.[116] It also calculated an average annual compound growth rate in average retail and residential rates through 2030 and 2035 and presented these results in its IRP Report.

The result is not a forecast of average retail and residential rates in those years because the calculations do not include the effects of changes in other costs in the generation and other functional areas of operations or in administrative and general expenses. Rather, the calculations are best used to quantify and compare the rate differentials among the various Portfolios in those years and to assess those differentials as a percentage of present rates.

The customer rate impacts are significant factors for the Commission to consider when evaluating each Portfolio and the potential pathways represented by each Portfolio. Not surprisingly, the lowest customer rate impact is Portfolio A. The greatest customer rate impacts are Portfolios D through F, which also are the most uncertain due to the unknown future carbon reduction targets, maturity and availability of technologies, costs of various technologies, and infrastructure required, among other factors.

The following figures show the annual and cumulative percentage increases in the average retail rates for each Portfolio, the first two with the cost of a carbon tax included in the revenue requirement (for Portfolios A through F) and the last two without the cost of a carbon tax included (for Portfolios B through F). The cumulative percentage increases on the average retail rates are significant, especially for Portfolios D through F, which are the high wind, SMR, and no new gas generation cases.

Begin Confidential Figures

[115] DEP 2020 IRP p. 190-191, including Table A-17.
[116] Response to ORS AIR 2-30, which includes an Excel workbook with the assumptions, data, and calculations.

Figure 12

[redacted]

Figure 13

[redacted]

Figure 14

[redacted]

Figure 15

[redacted]

End Confidential Figures

The following are observations we made when these analyses were performed. First, there are differences in the Company's calculations of the average retail rate effects and the Company's calculations of the PVRR for economic evaluation purposes. The first difference is that for its rate impact analysis, the Company calculated capital revenue requirements based on a ratemaking approach, which reflects the cost of the new resources on a declining cost basis as the installed cost is depreciated over its service life and accumulated deferred income taxes increase in the early years of its service life. However, for purposes of economic analyses, the Company calculated the capital revenue requirements on a levelized cost basis. These differences are normal modeling approaches that are typically used, and simply reflect the different purposes that each of the calculations are used for.

The second difference is that the Company calculated the average retail rate impact using the most recent capital structure and costs of capital authorized by the Commission and North Carolina Utilities Commissions (NCUC"),[117] but calculated the PVRR using a generic capital structure, generic cost of common equity, and an assumption regarding the incremental cost of debt.[118] The differences in the capital structure and costs of capital between the two calculations are confidential. The Company's calculation of the average retail rate impact is conceptually incorrect and should reflect the same assumptions as it used for the capital structure and cost of capital in the calculations of the PVRR. Only the incremental cost of capital applied to the rate base cost of the new resources, transmission, and other capital costs is recoverable in incremental rates. It is unlikely that correcting this error will materially change the average retail rate impact of the Portfolios, at least on a relative basis.

The third difference is that the Company calculated the average retail rate impact with depreciation expense using authorized depreciation rates for its existing resources rather than the depreciation rates for the new resources calculated in the PVRR as one (1) divided by the service life. The Company's calculation of the average retail rate impact is conceptually incorrect and should reflect the same assumptions it used for the depreciation expense in the PVRR. The Company's authorized depreciation rates do not reflect the service lives of new resources, but rather the remaining net book value and net salvage value that still must be recovered over the remaining lives of its existing resources. It is unlikely that correcting this error will materially change the average retail rate impact of the Portfolios, at least on a relative basis.

[117] Response to ORS AIR 2-10D-2 ((DEP) CONFIDENTIAL tab labeled "Common").
[118] Response to ORS AIR 2-30 DEP Cost of Service and Rate Impact (tab labeled "DEP-SC-COS.").

There are additional differences in other assumptions and methodologies, for example, in the combined federal and state income tax rates. These assumptions also should be consistent between the calculations of the average retail rate impact and the PVRR. Like the other errors, it is unlikely that correcting this error will materially change the average retail rate impact of the Portfolios, at least on a relative basis.

Finally, as noted in the Economic Evaluation of Portfolios and Sensitivities section of the Report, the Company's calculation of PVRR does not reflect the post-in-service capital expenditures and the related expenses, except for the battery resources, which include these costs in fixed O&M expenses. In addition to the PVRR, this understates the customer rate impacts of the Portfolios and sensitivities. However, it is unlikely that including these costs will materially affect the customer rate impacts of the Portfolios and sensitivities, at least on a relative basis.

Conclusions – Customer Rate Impacts

The average retail rate impact provides the Commission important information regarding the real-world impact of both the timing and magnitude of rate increases resulting from each of the Portfolios. For example, Portfolio A will result in a cumulative increase in the average retail customer rates of [redacted]% over the next 15 years. Portfolio A assumes there is no CO_2 tax. In contrast, Portfolio F will result in a cumulative increase in the average retail customer rates of [redacted]% over the next 15 years, assuming that there is a CO_2 tax and the cost of the CO_2 tax is included.

The Company's calculations of the average retail rate impact reflect the conceptual errors identified above. The calculations should use assumptions and methodologies that are consistent with the assumptions and methodologies used in the calculations of the PVRR, except for the levelization of the capital-related costs. However, the correction of these errors will not affect the ranking of the Portfolios on a PVRR basis; rather, it affects only the calculation of the potential average retail rate impact of the Portfolios, an important factor to consider, but not the primary factor. Further, it is unlikely that correcting the error will materially change the average retail rate impact of the Portfolios, at least on a relative basis.

Finally, the Company's calculations of the customer rate impacts are understated because they do not include the effects of post-in service capital expenditures and the related expenses. However, it is unlikely that including these costs will materially affect the customer rate impacts of the Portfolios and sensitivities, at least on a relative basis.

Recommendations – Customer Rate Impacts

22. The average retail rate impacts are an important consideration when assessing whether Portfolios and the pathways reflected in those Portfolios are reasonable. This should be considered in this IRP and future IRPs, but it does not require a modified IRP in this proceeding. **(N)**

23. ORS recommends the Company revise the calculation of the average retail rate impact on customers so that the assumptions and methodologies are consistent with the calculations of the PVRR, except for the levelization of the capital-related costs. We recommend this be included in a modified IRP in this proceeding. **(N)**

Transmission System Planning and Investment

The Company provided a summary of its transmission planning process in Chapter 7 and Appendix L of the IRP report. The Company indicated it has six 230 kilovolt (kV) and above transmission lines under construction or planned to start. It explained that significant transmission investments will be required in the future as it retires existing coal units and integrates new resources to its system. The Company included estimates of transmission costs with each portfolio, though the costs were developed as high-level estimates. The Company notes that extensive studies will be required to analyze the complex interactions of new resources on its system so that it can determine better transmission cost estimates.[119] For example, the Company developed its cost estimates assuming that replacement units would be developed at greenfield sites and it did not consider the savings that might be achieved by replacing resources on the same site.[120]

The Company developed transmission upgrades cost estimates based on three portfolios:[121]

- Base with Carbon Policy – $460 million.
- 70% CO_2 Reduction: High Wind Portfolio - $4.6 billion, including the cost of a new line to transport offshore wind power to its system.
- No New Natural Gas Portfolio - $4.8 billion.

Estimates of transmission costs that were used in the other three portfolios were derived by scaling costs from components in the above three forecasts. It is important to note that because transmission cost estimates were added to each portfolio in this way,

[119] DEP 2020 IRP pg. 55.
[120] *Id.* pg. 58 and 59.
[121] *Id.* pg. 58. Additional confidential details may be found in NCPS DR 3-17.

the Company did not include transmission costs associated with each generation resource option in the capacity expansion model (System Optimizer).[122] In addition, estimates of transmission costs required to retire DEP coal resources that were used are:

- Mayo and Roxboro 1-4: $80 Million

The Company also conducted a high level assessment of the transmission related costs associated with increasing the import capability between DEP/DEC and neighboring utilities by 5,000 to 10,000 MWs. DEP and DEC cost estimates for these transmission projects are:

- 5 GW import capability: $4-5 Billion
- 10 GW import capability: $8-10 Billion

The Company conducts detailed annual transmission studies that evaluates changes in load, generating capacity, transactions, and topography to maintain system reliability. In addition, the Company undergoes South Eastern Reliability Corporation (SERC) audits every 3 years to ensure compliance with North American Electric Reliability Corporation (NERC) standards.

Distribution Resource and Integrated System Operations Plans

Section 40(B)(2) contains the provision that "An integrated resource plan may include distribution resource plans or integrated system operations plans." The IRP report complies with this optional requirement and describes distribution resource plans most significantly in Chapter 15, where it discusses plans for ISOP. It also discusses Integrated Volt-Var Control (ICCV) in Appendix D.

<u>ISOP</u>

The Company believes this effort will be important "to address the trends in technology development, declining cost projections for energy storage and renewable resources, and customer adoption of electric demand modifying resources such as roof-top solar and EVs."[123]

According to the Company, more advanced distribution planning will allow it to better analyze the distribution and transmission systems to account for increasing variability of generation and two-way power flows on an increasingly distributed system. The

[122] NCPS DR 3-18.
[123] DEP 2020 IRP, pg. 125.

Company notes that it will have to upgrade its modeling data and tools. This process is underway and ISOP planning will be introduced in the 2022 IRP. The analyses conducted will involve developing circuit level forecasts on an hourly time scale. The Company is currently developing these forecasts to use in its Advanced Distribution Planning ("ADP") Toolset. Duke Energy is working with CYME, who it notes is an industry leader in distribution modeling to develop its ADP tool.

The Company asserts that its ISOP efforts will ultimately enable wider adoption of distributed resources based on these considerations:[124]

> The new functionality of the ADP toolset will enable planners to evaluate [Distributed Energy Resources] (including energy storage) as a potential solution for capacity needs and identify the most likely hourly patterns where potential new DERs would be needed to address local issues…
>
> ……the Company has also worked on developing screening processes to efficiently identify distribution upgrade needs that could potentially be deferred with non-traditional solutions.

These tools should allow the Company to evaluate resource options such as energy storage more quickly than it is currently able to do. ISOP will also allow for greater integration of the Company's distribution and transmission planning processes, which the Company asserts will allow future transmission and distribution plans to be conducted "from a more holistic perspective."[125]

IVVC

In its IRP Report, the Company introduced its newly developed IVVC, which has the objective of reducing winter peak demand and lowering overall energy consumption on its system, and involves the coordinated control of distribution equipment in substations and on distribution lines to optimize voltages and power factors on the distribution grid. Plans call for IVVC to "…allow the Company to more closely monitor and control the voltage on the distribution system and more effectively manage voltage fluctuations due to intermittency of renewable energy sources, while enabling energy and peak demand savings to our customers over time."[126]

[124] *Id*. pg. 127.
[125] DEP 2020 IRP, pg. 125.
[126] *Id.* pg. 134.

Other Considerations

Other Considerations - Stakeholder Engagement

The company discusses its stakeholder engagement efforts throughout the IRP report and on its website.[127] The Company's engagement process appears to be extensive as it solicits and incorporates stakeholder feedback across a variety of topics. The following items were addressed as a result of its stakeholder process:

- Inclusion of the 70% CO_2 Reduction Portfolios and the No New Gas Portfolio. Stakeholders provided input on resource planning, carbon reduction, energy efficiency, and demand response.[128]
- NREL Carbon-Free Resource Integration Study[129]
- Demand Side Management and IVVC Programs[130]
- Winter Peak Shaving Study[131]
- Carbon Reductions, Financial Impacts, and Customer Reliability[132]
- Resource Adequacy Study[133]
- ISOP Development. This included releasing a ISOP Stakeholder Engagement Report to document the process and key takeaways[134]

The Company appears to have gathered, documented, and incorporated stakeholder feedback into the IRP process across a breadth of subjects. However, ORS notes that it has presented several recommendations in this Report to be addressed in a future IRP and looks forward to addressing those issues with the Company and other parties in its stakeholder engagement process.

Other Considerations - Action Plan

Although the statutory requirements of Section 40 do not mandate that a utility include a short-term action plan, it is typical that most utility IRP Reports do include such a plan. DEP provides a chapter, Chapter 14 that discusses its short-term action plan. Table 14-

[127] https://www.duke-energy.com/our-company/sustainability/stakeholder-engagement
[128] DEP 2020 IRP p. 10, 22.
[129] *Id.* pg. 6.
[130] *Id.* pg. 12.
[131] *Id.* pg. 12.
[132] *Id.* pg. 18.
[133] *Id.* pg. 65.
[134] *Id.* pg. 130 and & https://www.duke-energy.com/_/media/pdfs/our-company/isop/icf-duke-isop-stakeholder-engagement-report.pdf?la=en

B[135] in the IRP Report (reproduced in Exhibit 1 below), provides a graphical summary listing the resource actions that may be addressed between 2021 and 2025. Those resources are categorized into retirements, additions, solar, solar with storage, biomass/hydro, cumulative EE, DSM, and IVVC. The information in Table 14-B is associated with the Base Case with Carbon Portfolio. Additional information regarding the other portfolios may be found in NCPS DR 7-1.

In addition to providing the short-term action plan for the 2020 IRP, Exhibit 1 below also compares the Company's 2020 IRP Report short-term action plan to its 2019 short-term action plan. The biggest changes between the two are accelerated coal unit retirements and a slower buildup of solar generation.

The Company's short-term action plan provides useful information for evaluating the resources the Company is likely to pursue over the next five years. One area in which the Company should improve the short-term action plan is to provide additional clarity about the status of resources that are included in the action plan. For example, in Table 14-B, the Company identifies CT retirements, CC additions, unnamed energy storage projects, and a nuclear uprate. Because those projects fall within the action plan time horizon they warrant additional specific details about the actions the Company is taking or will soon take regarding those resources.

For each of these categories of resources there is certain information that would be helpful to have located specifically in the action plan section. For retirements occurring within the five-year action plan window, it would be useful if the Company would provide information explaining the regulatory process and other significant hurdles that the Company will have to go through to actually retire those units. Based on the IRP, it would appear that the Company is proposing to retire the Darlington CT 1-4, 6-8, and 10 units as soon as the end of this year, yet it is not clear what steps the Company is taking or will have to take to formally retire those units. For the unnamed energy storage projects, since those are within the action plan horizon, it would be useful if the Company could identify the specific steps it will take to acquire those specific resources. For the nuclear uprate it would be useful if the Company could provide an update explaining the status of that project.

[135] DEP 2020 IRP, pg. 121.

Other Considerations - Southeast Energy Exchange Market ("SEEM")

On December 11, 2020, the Company filed with the NCUC information regarding the proposed SEEM platform agreement[136]. The Company stated that the SEEM will establish "a region-wide, automated, intra-hour platform to match buyers and sellers with the goal of more efficient bilateral trading and assumes utilization of unused transmission capacity to achieve cost savings for customers in the Southeast region of the country ("Platform")." The automated system will allow buyers and sellers to enter into trades on a 15-minute basis utilizing transmission capacity that otherwise would be unused.

To be clear, the SEEM will not be a new Regional Transmission Organization ("RTO") for the southeast similar to PJM or MISO, nor will it be an energy imbalance market similar to the Energy Imbalance Market ("EIM") that PacifiCorp and the California Independent System Operator launched in 2014, referred to as the Western EIM. The SEEM will allow participants to be able to trade with other members on a sub-hourly basis (every 15-minute basis) and do so using a platform that has been set up to automate the transaction process. In comparison, the Western EIM also allows participants to transact on a sub-hourly basis, however, the Western EIM is a real-time system that provides economically optimized dispatch instructions to participating members' generating units and derives payments based on locational marginal prices.

One important distinction is that the Western EIM sends dispatch signals to generating units, whereas the SEEM will only automate the process of allowing two parties to enter into a transaction, however, it will allow for transactions to take place on a 15 minute basis. The purpose of this discussion is to provide a brief description of the differences between the plans for the SEEM and the way an EIM operates.

In addition, DEP should incorporate details regarding the SEEM in the future IRP. ORS notes that PacifiCorp routinely provides information in its IRP to inform stakeholders about its involvement in the Western EIM, and to identify the benefits of its participation on an ongoing basis[137].

ORS recommends that in future IRPs, the Company should provide details regarding the status of the SEEM, details regarding important current and planned activities, and

[136] NCUC dockets: Docket Nos. E-7, Sub 1245 and E-2, Sub 1268; December 11, 2020 filing: https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=ee53f541-e7e5-41c2-b000-e32e5660873f
[137] Pacificorp 2019 IRP, pg. 2; https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_I.pdf

information regarding the monetary benefits that have been achieved by implementation of the SEEM.

Recommendations – Other Considerations – Action Plan

24. ORS recommends the Company provide additional details and status updates about resources included in the action plan, including CT retirements, unnamed energy storage projects, and the nuclear uprate. We recommend this information be included in a modified IRP in this proceeding. **(N)**

Recommendations – Other Considerations – SEEM

25. ORS recommends that in future IRPs, the Company provide details regarding the status of the SEEM, details regarding important current and planned activities, and information regarding the monetary benefits that have been or could be achieved by implementation of the SEEM. We recommend this be addressed in the future through the Company's stakeholder process. **(L)**

Review of DEP South Carolina Inc. 2020 Integrated Resource Planning Report

Exhibit 1

2019 DEP IRP Action Plan

Year	Retire (MW)		Additions (MW)		Solar (MW)	Solar with Storage (MW) Solar	Solar with Storage (MW) Storage	Biomass/ Hydro (MW)	EE (MW)	DSM (MW)	IVVC (MW)
2019											
2019											
2020	Asheville 1-2	384	Asheville CC	560	3005	0	0	264	48	478	0
2020			Nuclear Uprate	6							
2020			Energy Storage	15							
2020			Short-Term PPA	200							
2021	Darlington CT 1-4, 6-8, 10	497	Energy Storage	15	3274	0	0	116	90	487	0
2021			Short-Term PPA	100							
2021											
2021											
2022			Energy Storage	15	3477	0	0	116	131	495	0
2022			Short-Term PPA	200							
2022											
2022											
2023			Energy Storage	18	3774	10	2	113	170	505	0
2023			Short-Term PPA	100							
2023											
2023											
2024			Energy Storage	18	3977	10	2	112	226	514	0
2024			Short-Term PPA	500							
2024											
2025	Blewett, Weatherspoon	232									
2025											
2026											
2027											
2028											
2029	Roxboro 1-2	1053									
2030											
2031											
2032											
2033											
2034	Roxboro 3-4	1409									
2035											
2036	Mayo 1										
2037											
2038											
2039											
2040											
2041											
2042											
2043											
2044											
2045											
2046											
2047											
2048											
2049											

2020 DEP IRP Action Plan

Year	Retire (MW)		Additions (MW)		Solar (MW)	Solar with Storage (MW) Solar	Solar with Storage (MW) Storage	Biomass/ Hydro (MW)	EE (MW)	DSM (MW)	IVVC (MW)
2019											
2019											
2020											
2020											
2020											
2020											
2021	Darlington CT 1-4,6-8, 10	514	Asheville CC	560	2888	0	0	284	43	507	0
2021			Energy Storage	30							
2021											
2021											
2022			Energy Storage	15	3144	0	0	146	78	517	0
2022											
2022											
2022											
2023			Energy Storage	18	3430	0	0	135	111	521	9
2023											
2023											
2023											
2024			Energy Storage	18	3641	14	3	131	141	519	19
2024											
2024											
2025			Energy Storage	20	3850	14	3	131	185	329	96
2025			Nuclear Uprate	4							
2026	Blewett, Weatherspoon	232									
2027											
2028	Roxboro 3-4	1409									
2029	Roxboro 1-2,Mayo 1	1799									
2030											
2031											
2032											
2033											
2034											
2035											
2036											
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